EXHIBIT B

UNITED STATES DISTRICT COURT

NORTHERN DISTRICT OF TEXAS

DALLAS DIVISION

PEDRO RAMIREZ, JR., Individually and on Behalf of All Others Similarly Situated,	§	Civil Action No. 3:16-cv-03111-K
	§	CLASS ACTION
Plaintiff,	§	
vs.	§	
EXXON MOBIL CORPORATION, et al.,	§	
Defendants.	§	

DECLARATION OF CHARLOTTE J. WRIGHT, PH.D., CPA

I, Dr. Charlotte J. Wright, hereby declare and state as follows:

I. QUALIFICATIONS AND BACKGROUND INFORMATION

1. I am Regents Professor and Anadarko Petroleum Chair Emeritus in the School of Accounting in the Spears School of Business at Oklahoma State University in Stillwater, Oklahoma. I specialize in the area of oil and gas accounting and contract economics. I have spent a significant portion of my academic and professional career evaluating the economic and financial aspects of oil and gas contractual relationships. I was employed at Oklahoma State University from 1982 to 2017. I received my B.B.A. and M.P.A. from the University of Texas at Arlington. I received my Ph.D. in Business Administration, with a major in accounting and minors in finance and economics from the University of North Texas. I am a certified CPA in the State of Oklahoma. I have been actively involved in academic research, education, consulting, and practice in the oil and gas accounting and economic analysis area for the past 35 years.

2. I have authored two books, *Fundamentals of Oil and Gas Accounting* (editions 4, 5 and 6) and *International Petroleum Accounting.* Additionally, I have published at least 40 articles and presented numerous research papers, seminars, presentations, and speeches on oil and gas industry-related topics. One major focus of my research and consulting is accounting for oil and gas contracts and capital markets research. Among my publications are numerous articles addressing issues relevant to companies engaged in oil and gas producing operations.

3. I have won numerous honors and awards for both research and teaching. These include the ASWCPA National Literary Award (1986), Oklahoma Outstanding Accounting Educator (2009), Oklahoma State University Regent's Distinguished Research Award (2011), Oklahoma State University Spears School of Business Phillips 66 Excellence in Service Award (2014), and Oklahoma State University Spears School of Business Richard Poole Faculty Excellence Award (2014). In 2015 I was awarded the honorary title of Regents Professor, the highest academic rank attainable at Oklahoma State University.

4. In addition to my academic experience, I worked as a staff accountant at Atlantic Richfield Company from 1977 to 1979 and as a research fellow at the Institute for Petroleum Accounting Research at the University of North Texas from 1980 to 1982. Since 1982, I have developed and instructed executive and continuing education courses focusing on various aspects of oil and gas economic and accounting issues, worked as a consultant for a number of oil and gas companies and firms, and have provided litigation support primarily in legal matters involving oil and gas industry-related matters.

5. A copy of my curriculum vitae is attached as Exhibit 1 to this declaration.

II. SUMMARY OF OPINIONS

6. Based on my extensive knowledge of accounting practices and authoritative guidance, especially related to companies engaged in oil and gas-related activities, I have been retained by counsel for lead plaintiff in the above-captioned matter to offer my opinion regarding several issues concerning financial and accounting disclosures by Exxon Mobil Corporation (Exxon or the Company). As further detailed below, my analysis focuses on two specific areas

of Exxon's operations: (1) bitumen heavy crude operations located in Alberta, Canada;[1] and (2) dry gas operations located in the Rocky Mountain region.

7. The first matter I have been asked to opine upon is whether, at the time Exxon filed its 2015 Form 10-K report with the United States Securities and Exchange Commission (SEC), the Canadian Bitumen Operations were operating at a loss; and if so, whether Exxon was required to disclose that fact pursuant to Generally Accepted Accounting Principles (GAAP),[2] accounting and disclosure requirements established by the SEC and/or other established accounting practices and guidance. As further detailed below, it is my opinion that the Canadian Bitumen Operations were operating at a loss at the time Exxon filed its 2015 Form 10-K report, and that Exxon was required to disclose that fact pursuant to GAAP, as well as various FASB authoritative guidance and SEC regulations.

8. The second matter I have been asked to opine upon is whether Exxon's 2015 Form 10-K and 2016 Form 10-Q reports violated applicable GAAP provisions, FASB guidance, SEC requirements and/or other established accounting principles and practices, by failing to provide more detailed and truthful disclosures concerning the likelihood that the Kearl project would not satisfy the SEC definition for "proved reserves" at year-end 2016. As further detailed below, it is my opinion that Exxon's 2015 Form 10-K and 2016 Form 10-Q reports violated GAAP, as well as various FASB authoritative guidance and SEC regulations, by failing to

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[1] These operations are comprised of an open-pit mining operation located at Kearl Lake and an in-situ operation located at Cold Lake. The Kearl project is a joint venture between Exxon and its consolidated subsidiary, Imperial Oil Limited (Imperial Oil), and the Cold Lake project is owned and operated by Imperial Oil. The Kearl project and the Cold Lake project are collectively referred to herein as the "Canadian Bitumen Operations."

[2] GAAP comprises the standards recognized by the accounting profession as the conventions, rules and procedures necessary to define accepted accounting practices at a particular time. The SEC has the statutory authority for the promulgation of GAAP for public companies and has generally delegated that authority to the Financial Accounting Standards Board (FASB). SEC Regulation S-X, 17 C.F.R. §210.4-01(a)(1), provides that financial statements filed with the SEC that are not presented in conformity with GAAP will be presumed to be misleading, despite footnotes or other disclosures.

provide more detailed and truthful disclosures concerning the likelihood that the Kearl project would not satisfy the SEC definition for "proved reserves" at year-end 2016.

9. The third matter I have been asked to opine upon is whether Exxon's filings with the SEC during the period of March 31, 2014 through January 30, 2017 (the Class Period) violated applicable GAAP provisions, FASB guidance, SEC requirements and/or other established accounting principles and practices, by failing to disclose that, contrary to the Company's statements to investors, Exxon did not incorporate a greenhouse gas (GHG) or carbon "proxy cost" into the Company's calculations concerning its investment and asset valuation processes for the Canadian Bitumen Operations. As further detailed below, it is my opinion that, at the very least, Exxon's 2015 Form 10-K and 2016 Form 10-Q reports violated GAAP, as well as various FASB authoritative guidance and SEC regulations by failing to disclose that, contrary to the Company's statements to investors, Exxon did not incorporate a GHG "proxy cost" into the Company's calculations concerning its investment and asset valuation processes for the Canadian Bitumen Operations.

10. The fourth matter I have been asked to opine upon is whether Exxon violated applicable GAAP provisions, FASB guidance, SEC requirements and/or other established accounting principles and practices, by failing to incorporate a GHG "proxy cost" into the Company's estimate of the proved reserves and/or asset impairment calculations for the Canadian Bitumen Operations during the Class Period. As further detailed below, it is my opinion that Exxon should have incorporated a GHG "proxy cost" into its estimate of proved reserve quantities and its asset impairment calculations for the Canadian Bitumen Operations, and that its failure to do so caused the Company's filings with the SEC during the Class Period to be materially mistated in violation of GAAP, as well as various FASB authoritative guidance and SEC regulations.

11. The final matter I have been asked to opine upon concerns the long-lived asset impairment charge Exxon recorded in its 2016 Form 10-K report pursuant to the FASB guidance codified in FASB Accounting Standards Codification (ASC) 360-10-05, “Impairment or Disposal of Long-Lived Assets.” Specifically, on January 31, 2017, Exxon announced its fourth quarter and full year financial results for 2016. At that time, the Company announced that it was recording a $2 billion asset impairment charge “largely related to dry gas operations in the Rocky Mountain region.” The charge was subsequently confirmed in Exxon’s 2016 Form 10-K, filed on February 22, 2017, wherein the Company clarified that the previously announced $2 billion asset impairment charge was actually a $3.3 billion charge on a pretax basis.[3]

12. With regard to this final matter, I have been asked to offer my opinion as to whether, from an accounting perspective, the 2016 Dry Gas Impairment Charge should have been recorded in Exxon’s public financial statements for accounting periods prior to the fourth quarter and year ended December 31, 2016. As further detailed below, it is my opinion that proper application of ASC 360-10 to the Rocky Mountain dry gas operations (at issue in the 2016 Dry Gas Impairment Charge) would have resulted in recognition of impairment by no later than the end of the calendar year in 2015, and accordingly, Exxon should have taken an impairment charge related to those assets by at least the time the Company disclosed its fourth quarter and full year financial results for 2015. Moreover, it is also my opinion that the impairment charge that should have been taken at year-end 2015 clearly would have been material, given the size of the charge Exxon ultimately took at year-end 2016 (approximately $2 billion on a post-tax basis) and that failure to recognize the impairment charge in 2015 resulted in misstated earnings which masked the Company’s failure to meet analysts’ consensus expectations for the enterprise. As a result, it is my opinion that Exxon’s 2015 Form 10-K and

[3] This impairment charge is referred to herein as the “2016 Dry Gas Impairment Charge.”

2016 Form 10-Q reports violated GAAP by failing to record an appropriate asset impairment charge related to Exxon's Rocky Mountain dry gas operations.

13. I believe a detailed examination of Exxon's internal records will confirm the above opinions.

III. RELEVANT GAAP PROVISIONS AND SEC DISCLOSURE RULES

A. ASC 275—Risks and Uncertainties

14. According to the FASB's Conceptual Framework[4], the objective of general purpose financial reporting is to provide information about a reporting entity that is useful to existing and potential investors, lenders, and other creditors in making decisions about providing resources to the entity. Existing and potential investors, lenders, and other creditors must assess the timing, amount and uncertainty of future net cash inflows to the entity. In order to assess an entity's prospects for future net cash inflows, existing and potential investors, lenders, and other creditors need information about the resources of the entity, claims against the entity, and how efficiently and effectively the entity's management and governing board have discharged their responsibilities to use the entity's resources.

15. Financial statements and reports are the central feature of financial reporting. General purpose financial statements and reports are designed to provide information about the entity's economic resources and the claims against the reporting entity. Financial reports also provide information about the effects of transactions and other events that change a reporting entity's economic resources and claims. Both types of information provide useful input for

[4] The FASB Concepts Statements are intended to serve the public interest by setting the objectives, qualitative characteristics, and other concepts that guide selection of economic phenomena to be recognized and measured for financial reporting and their display in financial statements or related means of communicating information to those who are interested. Concepts Statements guide the Board in developing sound accounting principles and provide the Board and its constituents with an understanding of the appropriate content and inherent limitations of financial reporting.

decisions about providing resources to an entity. (Statement of Financial Accounting Concepts (SFAC) No. 8, *Conceptual Framework for Financial Reporting*, FASB, pp. 1-3.)

16. According to ASC 275-10-05-01:

> Financial statements provide information about certain current conditions and trends that help users in predicting reporting entities' future cash flows and results of operations. The quality of users' predictions depends to a significant degree on their assessment of the risks and uncertainties inherent in entities' operations and of the information about those operations that financial reporting provides.

17. Estimates are inherent in financial statement preparation. Accordingly, ASC 275 requires that management provide discussion about the risks and uncertainties inherent in significant estimates when it is "reasonably possible" that the estimate will change materially in the next year. If management knows, by the time the financial statements are issued, that a reasonable possibility exists that a significant estimate or estimates underpinning the recognition or measurement of element(s) of the financial statements is likely to change in the next 12 months and the effect of such change will be material, management is required to make a complete and fulsome disclosure of all the relevant facts. This disclosure must include an estimate of the effect of a change in a condition, situation, or set of circumstances that existed at the date of the financial statements and an indication that it is at least reasonably possible that a change in the estimate will occur in the near term. The disclosures required as a consequence of changes in certain significant estimates are described in ASC 275-10-50-6:

> **Certain Significant Estimates:**
> This Subtopic requires discussion of estimates when, based on known information available before the financial statements are issued or are available to be issued (as discussed in Section 855-10-25), it is **reasonably possible** that the estimate will change in the **near term** and the effect of the change will be material. The estimate of the effect of a change in a condition, situation, or set of circumstances that existed at the date of the financial statements shall be disclosed and the evaluation shall be based on known information available before the financial statements are issued or are available to be issued (as discussed in Section 855-10-25).

18. In addition, the American Institute of CPAs (AICPA) published *Audit & Accounting Guide: Entities With Oil and Gas Producing Activities* (AICPA 2014) for the express purpose of assisting management in preparing financial statements in conformity with U.S. GAAP and assisting practitioners in performing and reporting their audit engagements. In paragraph 8.162, the AICPA identifies risks and uncertainties of special significance to accurate reporting of oil and gas reserves and their effect of estimates of future cash flows:

> FASB ASC 275, Risks and Uncertainties, and paragraphs 50-54 of FASB ASC 360-10-55 require disclosure of significant estimates and concentrations. The auditor should evaluate the appropriateness of the entity's disclosures related to significant concentrations and estimates. Significant estimates prevalent in the oil and gas industry include, but are not limited to, the following: Proved oil and gas reserve and cash flow estimates, including DD&A, impairments and purchase price allocations, which are all affected by oil and gas reserve estimates. (p.147)

B. ASC 932—Extractive Industries: Oil and Gas, including SEC Regulation S-X Rule 4-10

19. In addition to general-purpose GAAP requirements, public oil and gas companies must comply with SEC regulations and standards issued by the FASB, including any industry-specific standards. ASC 932 is a codification of all FASB accounting and disclosure requirements specifically addressing accounting and disclosures mandated for companies engaged in oil and gas producing activities. ASC 932 is aligned with the SEC's rules for accounting using the successful efforts method and for disclosure of information relating to oil and gas producing activities as set forth in SEC Regulation S-X Rule 4-10. As such, the provisions of ASC 932 are applicable to Exxon.

20. A unique accounting issue faced by oil and gas producing companies is that their main asset, their oil and gas reserves, do not appear on the company's balance sheet as an asset. Instead, the assets reported on the balance sheet reflect only capitalized historical costs associated with property acquisition, successful exploratory drilling, development drilling, and

development cost associated with the oil and gas reserves. The historical costs of finding and developing oil and gas reserves are not an estimate of the fair value of the oil and gas reserves.

21. Because the oil and gas assets reported in the balance sheet are based on historical costs, they do not provide all information critical to investors in estimating an oil and gas company's future cash flows. As a consequence, the SEC and the FASB require that all public companies engaged in significant oil and gas activities must supplement their audited financial statements with additional oil and gas reserve-related disclosures, as required by ASC 932 and SEC Regulation S-X Rule 4-10. These supplemental disclosures require significant disclosure of information about the entity's oil and gas producing activities, including detailed disclosures concerning its proved reserves.

22. The SEC defines proved oil and gas reserves in Regulation S-X Rule 4-10(a)(22):

> Proved oil and gas reserves. Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible-from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations-prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

This definition of proved reserves also appears in ASC 932-10-S99-1. If reserves do not meet this definition they *cannot* be reported as proved reserves. If reserves cannot be considered proved, they are unproved and thus may be treated as probable or possible; however, they may not be reported as being proved.

23. One of the most critical aspects in the above definition of proved reserves is, in order to qualify as such, the quantities of oil and gas reserves must be *economically producible* under current economic conditions, *i.e.*, conditions existing as of the financial statement date.

The FASB defines economically producibility as meaning that production of a resource is expected to generate a profit. According to ASC 932-10-20:

> The term economically producible, as it relates to a resource, means a resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil- and gas-producing activities.

24. In order to determine whether specific reserves meet the SEC's test for economic producibility under existing economic conditions (and thus meet the definition of proved reserves), registrants are required to consider both historical prices and current costs. The SEC Regulation S-X Rule 4-10(a)(22)(v) indicates that sales prices to be used in assessing existing economic conditions is the arithmetic average of the first-day-of-the-month prices achieved for the prior 12 months, unless future sales price commitments are defined by contractual arrangements:

> (v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

25. The first-day-of-the-month prices should be adjusted to reflect the conditions and situations specifically affecting all reserves and resources (*i.e.*, the physical location, quality of the particular proved reserves being estimated, etc.). The estimated costs to be used in this assessment are those existing at period end applied to each year in the future for which the specific reserves are expected to be produced. Cost inflation escalations are not considered; however, known cost changes in the future, including tax and royalty changes as well as major maintenance, are included.

26. In order to continue to be classified as proved reserves, the reserves must continue to meet the definition of proved reserves. If subsequent evaluations result in the determination

that previously classified proved reserves no longer qualify as being economically producible, those reserves are no longer proved reserves and must be "de-booked" (*i.e.*, reclassified from proved to unproved). The SEC rules require disclosure of revisions of previously estimated quantities of proved reserves. De-booking of proved reserves appears as a downward or negative revision to the beginning-of-the-year proved reserves quantities reported in the SEC Regulation S-X Rule 4-10 mandated proved reserves disclosures in the financial statements.

C. ASC 360-10-35—Subsequent Measurement: Impairment or Disposal of Long-Lived Assets

1. Asset Impairment and Trigger Events

27. According to ASC 360-10-20: "Impairment is the condition that exists when the carrying amount of a long-lived asset or asset group exceeds its fair value." The FASB requires recognition of an impairment loss in situations where the carrying amount of a long-lived asset or asset group is not recoverable and exceeds its fair value:

> An impairment loss shall be recognized only if the carrying amount of a long-lived asset (asset group) is not recoverable and exceeds its fair value. The carrying amount of a long-lived asset (asset group) is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset (asset group). That assessment shall be based on the carrying amount of the asset (asset group) at the date it is tested for recoverability, whether in use (see paragraph 360-10-35-33) or under development (see paragraph 360-10-35-34). An impairment loss shall be measured as the amount by which the carrying amount of a long-lived asset (asset group) exceeds its fair value. (ASC 360-10-35-17).

This provision applies to public companies, including those engaged in oil and gas producing activities.

28. ASC 360-10-35 does not require routine testing for possible impairment. Instead, ASC 360-10-35-21 requires that, "A long-lived asset (asset group) shall be tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable." Notably, the use of the word "*may*" indicates that circumstances

merely raising the possibility that the carrying amount of an asset may be unrecoverable requires that the asset or asset group be assessed and tested for impairment. Events and circumstances that are considered potential impairment indicators are frequently referred to as "trigger events," as they indicate the necessity that an accounting impairment test be performed.

29. ASC 360-10-35-21 provides examples of possible impairment indicators (triggers). These examples of such events or changes in circumstances include, but are not limited to:

- A significant decrease in the market price of a long-lived asset (asset group)
- A significant adverse change in the extent or manner in which a long-lived asset (asset group) is being used or in its physical condition
- A significant adverse change in legal factors or in the business climate that could affect the value of a long-lived asset (asset group), including an adverse action or assessment by a regulator
- An accumulation of costs significantly in excess of the amount originally expected for the acquisition or construction of a long-lived asset (asset group)
- A current-period operating or cash flow loss combined with a history of operating or cash flow losses or a projection or forecast that demonstrates continuing losses associated with the use of a long-lived asset (asset group)
- A current expectation that, more likely than not, a long-lived asset (asset group) will be sold or otherwise disposed of significantly before the end of its previously estimated useful life. The term *more likely than not* refers to a level of likelihood that is more than 50 percent.

(ASC 360-10-35-21).

30. Additionally, in *Petroleum Accounting 7th ed.*,[5] Exxon's outside audit firm PricewaterhouseCoopers LLP (PwC) identifies oil and gas industry-specific impairment triggers:

- The passage of time due to unit-of-production amortization, as explained in the last section.

[5] John Brady, Charles Chang, Dennis R. Jennings, Rich Shappard, *Petroleum Accounting 7th ed.*, copyright 2011 by PricewaterhouseCoopers LLP.

- Lower expected future oil and gas prices (such as the prices used by management in evaluating whether to develop or acquire properties).
- Actual or expected future development or operating costs are significantly more than previously anticipated for a group of properties (e.g., significant AFE overruns or higher oil field or other service costs with no significant upward revisions in reserve estimates).
- Significant downward revisions to a field's reserves estimates.
- Significant increase in capitalized asset retirement costs.
- Significant adverse change in legislative or regulatory climate.

(pp. 322-323).

31. Brady, *et al*., indicate that impairment must be recognized in the accounts of an oil and gas company in the quarter in which the impairment-related conditions first occurred:

> SEC registrants must address impairment in the operating results of the quarter in which the impairment-related events or circumstances occur that indicate an asset group may be impaired. Thus, impairment losses are reported in the quarter related to the event, as opposed to year-end operating results. (p. 323).[6]

2. Impairment Testing and Impairment Loss Recognition

32. After a trigger event has been identified, the next step is to estimate the asset's (asset group) expected future (undiscounted) net cash flows which are then compared to the net carrying value of the asset or asset group in question. This is often referred to as a "recoverability test." If the sum of these future undiscounted net cash flows from the expected use and eventual disposition of the asset fail to exceed the carrying value of the asset on the company's books, the asset is considered to be impaired and an impairment loss must be recorded.

33. According to ASC 360-10-35-17, impairment losses are measured as the amount by which the carrying amount of a long-lived asset or asset group exceeds its fair value. For this

[6] Notably, all of the authors of *Petroleum Accounting 7th ed.* are either current or retired partners of PwC, Exxon's outside audit firm.

purpose, fair value is often measured by discounting the net cash flows (that were determined in the recoverability test). Impairment is recorded as an impairment loss that results in a reduction to the capitalized cost of the asset or asset group and a reduction in net income for the period in which the impairment was determined.

34. The accounting rules governing Exxon's impairment testing of its capitalized cost of proved oil and gas assets (*i.e.*, properties with proved reserves) are set forth in ASC 360-10 35. Impairment accounting rules for "unproved properties" are prescribed by the provisions of ASC 932-360-35 and SEC Regulation S-X Rule 4-10.

D. SEC Regulation S-K Item 303—Management's Discussion and Analysis

35. SEC Regulation S-K Item 303 requires a discussion of results of operations and other information necessary to an understanding of a registrant's financial condition, changes in financial condition and results of operations. According to the SEC, "This includes unusual or infrequent transactions, known trends or uncertainties that have had, or might reasonably be expected to have, a favorable or unfavorable material effect on revenue, operating income or net income and the relationship between revenue and the costs of the revenue."

36. The SEC describes the purpose of the MD&A requirements as "not complicated," stating that it is to "provide readers information 'necessary to an understanding of [a company's] financial condition, changes in financial condition and results of operations.'" Moreover, the SEC has stated that the MD&A requirements are intended to satisfy the following three principal objectives:

- provide a narrative explanation of a company's financial statements that enables investors to see the company through the eyes of management;
- enhance the overall financial disclosure and provide the context within which financial information should be analyzed; and

- provide information about the quality of, and potential variability of, a company's earnings and cash flow, so that investors can ascertain the likelihood that past performance is indicative of future performance.

37. Accordingly, the SEC has clarified that the MD&A requires not only "discussion" but also "analysis" of known material trends, and that such analysis should not be merely a restatement of the financial statement information in a narrative form.[7]

E. SEC Staff Accounting Bulletin No. 99—Materiality

38. SEC Staff Accounting Bulletin No. 99, Materiality (SAB 99) sets forth the generally accepted methods to evaluate materiality in relation to the financial statements of SEC registrants. Among other things, SAB 99 states that: "The omission of an item in a financial report is material if, in the light of surrounding circumstances, the magnitude of the item is such that it is probable that the judgment of a reasonable person relying upon the report would have been changed or influenced by the inclusion of the item."

39. SAB 99 also states that both "quantitative" and "qualitative" factors must be considered in assessing materiality, and lists considerations that may render material a quantitatively small misstatement of a financial statement item, including:

- Whether the misstatement masks a change in earnings or other trends.
- Whether the misstatement hides a failure to meet analysts' consensus expectations for the enterprise.
- Whether the misstatement changes a loss into income or vice versa.
- Whether the misstatement concerns a segment or other portion of the registrant's business that has been identified as playing a significant role in the registrant's operations or profitability.

[7] Interpretation: Commission Guidance Regarding Management's Discussion and Analysis of Financial Condition and Results of Operations, Securities and Exchange Commission 17 C.F.R. Parts 211, 231 and 241 (Release Nos. 33-8350, 34-48960; FR-72).

IV. ANALYSIS

A. The Canadian Bitumen Operations

1. Disclosure Obligations Regarding the Canadian Bitumen Operations' Lack of Profitability

40. To assess the profitability of the Canadian Bitumen Operations around year-end 2015, I conducted a multi-step analysis, as detailed in paragraphs 41-53 below. Based on this analysis, it is my opinion that the Canadian Bitumen Operations were operating at a loss from at least mid-November 2015 through mid-April 2016.

41. For purposes of this declaration, I have reviewed Imperial Oil's annual Report 51-101F1 filings[8] for 2015 and 2016. Canadian regulatory requirements indicate that these reports are to contain detailed information regarding the Canadian Bitumen Operations. Among other things, this information is to include, on a quarterly basis: (1) the average price received per barrel (bbl) of bitumen from the Canadian Bitumen Operations (Average Price Received); (2) the average cost of production per bbl of bitumen from the Canadian Bitumen Operations (Average Production Costs); and (3) the average royalties paid per bbl of bitumen from the Canadian Bitumen Operations (Average Royalties Paid).

42. From these reports, I was able to discern the following information for years 2015 and 2016, measured in Canadian Dollars (CAD):

[8] A Report 51-101F1 *Statement of Reserves Data and Other Oil and Gas Information* filing is a document that all publicly traded Canadian companies with significant oil and gas activities must file on an annual basis with the Canadian Securities Administrators. The Canadian Securities Administrators is an umbrella organization that coordinates the activity of securities regulators from Canada's 10 provinces and 3 territories, including the Alberta Securities Commission. *https://www.securities-administrators.ca*.

Table 1
Details re Canadian Bitumen Operations (in CAD) 2015-2016 (rounded)

Reported Data	Units	2015				2016			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Avg. Price Received	CAD/bbl	29.43	53.90	36.52	24.87	13.31	33.46	33.29	37.84
Avg. Royalties Paid	CAD/bbl	2.03	4.42	3.78	1.88	1.05	3.81	3.19	3.32
Avg. Production Costs	CAD/bbl	31.78	25.46	23.18	22.06	23.04	22.92	25.83	25.25

43. Next, I used the figures set forth in Table 1 to calculate the minimum average per bbl price, in United States Dollars (USD), that the Company would have needed to receive during any given quarter in order for the Canadian Bitumen Operations to avoid losing money. First, using the daily end-of-day Canadian exchange rates provided by the Bank of Canada, I calculated the average quarterly exchange rates for converting CAD to USD. I then used those exchange rates to convert the Average Price Received, Average Royalties Paid and Average Production Costs from Table 1 into amounts measured in USD. I then calculated the "Average Total Production and Royalty Cost/bbl" by summing the Average Production Costs and Average Royalties Paid (as reported in Imperial Oil's quarterly Report 51-101F1 filings). These amounts are set forth below in Table 2:

Table 2
Details re Canadian Bitumen Operations (in USD) 2015-2016 (rounded)

Reported Data	Units	2015				2016			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Avg. Quarterly Canadian Exchange Rate	USD/CAD	0.80559	0.81360	0.76438	0.74920	0.72946	0.77629	0.76649	0.74928
Avg. Price Received	USD/bbl	23.71	43.85	27.92	18.63	9.71	25.97	25.52	28.35
Avg. Royalties Paid	USD/bbl	1.64	3.60	2.89	1.41	0.77	2.96	2.45	2.49
Avg. Production Costs	USD/bbl	25.60	20.71	17.72	16.53	16.81	17.79	19.80	18.92
Avg. Total Production and Royalty Cost/bbl	USD/bbl	27.24	24.31	20.61	17.94	17.57	20.75	22.24	21.41

44. Assuming the information in Imperial Oil's quarterly Report 51-101F1 filings is accurate, the Average Total Production and Royalty Cost/bbl entries in Table 2 above reflect the ***minimum*** average per bbl price that would have to be received during any given quarter in order

for the Canadian Bitumen Operations to avoid losing money (*i.e.*, in order to cover the minimum average total production costs and royalties paid in connection with the production of bitumen from the Canadian Bitumen Operations).

45. The next steps in my analysis were designed to determine the average published spot price of crude oil required during any given quarter in order for Exxon and Imperial Oil to cover the Average Total Production and Royalty Cost/bbl figures set forth in Table 2 above.

46. There are many varieties of crude oils produced around the world. Crude oils are comprised of complex mixtures of various hydrocarbon compounds along with varying amounts of other chemicals (*i.e.*, sulfur, nitrogen, heavy metals). Reservoirs in the same field do not necessarily produce crude with identical chemical composition. Although the prices of the various crudes move broadly together, numerous factors influence the selling price that a particular crude oil will bring. Two of these factors that are commonly cited are quality and physical location. The exact composition of any particular production stream determines the mix and value of products that can be obtained by refining that particular production stream. The location of the production site relative to major markets for refining and the available modes of transportation influence the cost of transporting the production to market/the refinery. Bitumen production pricing is further complicated by the need to add a diluent to the produced bitumen in order to transport the product to market.

47. Ultimately, the value of a raw production involves identifying a benchmark price for production in a particular market and then, in order to account for differences between the quality, physical location, etc. of a particular commodity being priced and that of the benchmark being referenced, a discount or premium, called a "differential," is subtracted from or added to the benchmark price. For bitumen produced from Alberta, Canada, such as the Canadian Bitumen Operations, the most commonly referenced benchmark is Western Canadian Select

(WCS), which corresponds to a heavy, sour oil comprised mostly of Canadian bitumen that is sold for immediate delivery at the Husky oil terminal at Hardisty, Alberta.

48. Accordingly, I next examined the historical USD daily spot prices for the WCS benchmark, as reported by Bloomberg. From these daily spot prices, I was able to calculate the following quarterly average WCS (USD/bbl) prices for 2015 and 2016:

Table 3
Average WCS Benchmark Daily Spot Price (in USD/bbl) 2015-2016 (rounded)

Reported Data	Units	2015				2016			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Avg. WCS Daily Spot Price	USD/bbl	35.03	48.34	31.54	27.82	20.26	32.84	30.67	34.34

49. By comparing the Average Price Received (USD/bbl) data from Table 2 to the Average WCS Daily Spot Price (USD/bbl) data in Table 3, I was able to estimate the Average WCS Price Discount Differentials (USD/bbl) for the Canadian Bitumen Operations in 2015 and 2016. These estimates are reported in Table 4 below. The Average WCS Price Discount Differentials (USD/bbl) reported in Table 4 below reflect the estimated discounts Exxon and Imperial Oil received in connection with bitumen sales from the Canadian Bitumen Operations, as compared to the Average WCS Daily Spot Price (USD/bbl):

Table 4
Average WCS Price Discount Differentials (in USD) 2015-2016 (rounded)

	Units	2015				2016			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Avg. WCS Price Discount Differential	USD/bbl	11.32	4.48	3.63	9.19	10.55	6.86	5.15	5.99

50. Next, I added the estimated Average WCS Price Discount Differentials from Table 4 to the Average Total Production and Royalty Cost/bbl figures reported in Table 2, in order to estimate the Average Minimum WCS Breakeven Prices for the Canadian Bitumen Operations in 2015 and 2016, as set forth in Table 5 below:

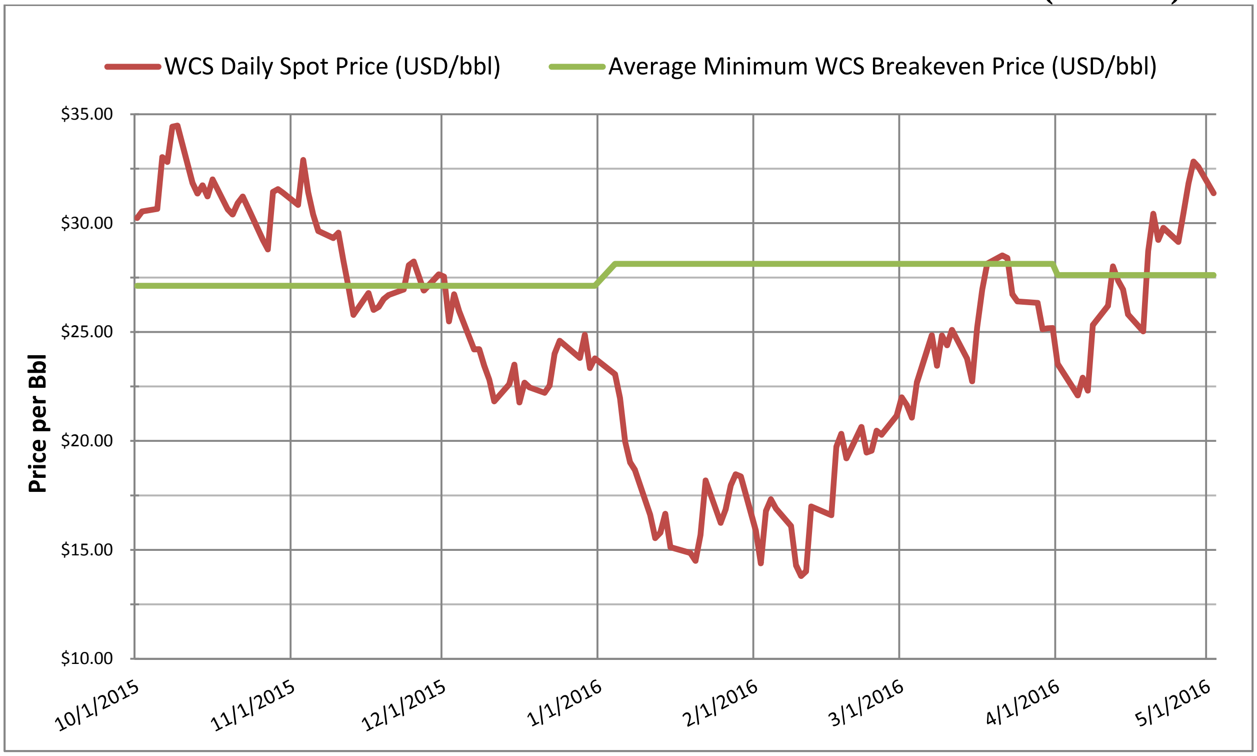
Table 5
Average Minimum WCS Breakeven Prices (in USD) 2015-2016 (rounded)

	Units	2015				2016			
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Avg. Total Production and Royalty Cost/bbl	USD/bbl	27.24	24.31	20.61	17.94	17.57	20.75	22.24	21.41
Avg. WCS Price Discount Differential	USD/bbl	11.32	4.48	3.63	9.19	10.55	6.86	5.15	5.99
Avg. Minimum WCS Breakeven Price	USD/bbl	38.56	28.80	24.23	27.12	28.13	27.61	27.40	27.39

51. The Average Minimum WCS Breakeven Prices reported in Table 5 above represent the ***minimum*** average WCS benchmark spot price that would be required in any given quarter in order for the Canadian Bitumen Operations to avoid losing money (*i.e.*, in order to cover the minimum average total production costs and royalties paid in connection with the production of bitumen from the Canadian Bitumen Operations). As detailed in paragraphs 42-50 above, these figures were derived by simply calculating the average quarterly discount differential the Canadian Bitumen Operations received from WCS benchmark prices and summing those discount differentials together with the Average Total Production and Royalty Cost/bbl for the Canadian Bitumen Operations, as disclosed in Imperial Oil's 51-101F1 filings.

52. For the next step in my analysis, I compared the Average Minimum WCS Breakeven Prices (USD/bbl) reported in Table 5 to the WCS Daily Spot Prices (USD/bbl), as reported by Bloomberg. As illustrated by the graph in Figure 1 below, this comparison reveals that the WCS Daily Spot Price (USD/bbl) fell below the Canadian Bitumen Operations' Average Minimum WCS Breakeven Price (USD/bbl) on nearly all days during the period of November 12, 2015 through April 18, 2016:

FIGURE 1
WCS DAILY SPOT PRICE (USD/bbl) VERSUS CANADIAN BITUMEN OPERATIONS' AVERAGE MINIMUM WCS BREAKEVEN PRICE (USD/bbl)



53. Indeed, as set forth in the table attached as Exhibit 2 to this declaration, during the period of November 12, 2015 through April 18, 2016, the WCS Daily Spot Price (USD/bbl) fell below the Canadian Bitumen Operations' Average Minimum WCS Breakeven Price (USD/bbl) on ***all but eight days*** during this period.

54. Based on the above analysis, it is my opinion that the Canadian Bitumen Operations were losing money for at least the period covering the general timeframe from mid-November 2015 through mid-April 2016.

55. Exxon's 2015 Form 10-K was filed with the SEC on February 24, 2016. At the time, Exxon did not disclose that the Canadian Bitumen Operations had been operating at a loss for more than three months. Instead, Exxon disclosed only that during 2015, the average price received per barrel of bitumen produced from the Canadian Bitumen Operations was $25.07 USD, and the average production cost per barrel of bitumen produced from the Canadian

Bitumen Operations was $19.20 USD, implying a per barrel profit of $5.87 USD. An excerpt of the relevant table from page 9 of Exxon's 2015 Form 10-K is provided below:

B. Production Prices and Production Costs

The table below summarizes average production prices and average production costs by geographic area and by product type for the last three years.

	United States	Canada/ S. America	Europe	Africa	Asia	Australia/ Oceania	Total
During 2015				*(dollars per unit)*			
Consolidated Subsidiaries							
Average production prices							
Crude oil, per barrel	41.87	44.30	49.04	51.01	48.30	49.56	47.75
NGL, per barrel	16.96	21.91	27.50	33.41	21.14	29.75	22.16
Natural gas, per thousand cubic feet	1.65	1.78	6.47	1.57	2.02	5.13	2.95
Bitumen, per barrel	-	25.07	-	-	-	-	25.07
Synthetic oil, per barrel	-	48.15	-	-	-	-	48.15
Average production costs, per oil-equivalent barrel - total	12.50	22.68	15.86	10.31	7.71	8.86	12.97
Average production costs, per barrel - bitumen	-	19.20	-	-	-	-	19.20
Average production costs, per barrel - synthetic oil	-	41.83	-	-	-	-	41.83

56. This disclosure was materially misleading, in light of my analysis above regarding the operating losses incurred by the Canadian Bitumen Operations from at least mid-November 2015 through the date on which Exxon's 2015 Form 10-K was filed. Without more, the disclosure described in paragraph 55 above masked the start of a materially unfavorable trend in the profitability of the Canadian Bitumen Operations. As indicated in paragraph 39 above, included among the factors that the SEC's SAB 99 lists as indications of materiality is whether the item masks a change in earnings or other trends, and whether the item concerns a segment or other portion of the registrant's business that has been identified as playing a significant role in the registrant's operations. Both are true here. The Canadian Bitumen Operations were clearly an important segment or portion of Exxon's business going forward. Among other things, Exxon's Canadian bitumen proved reserves at year-end 2015 represented approximately 31% of Exxon's total liquids proved reserves and 18% of the Company's combined liquids and natural gas world-wide proved reserves. Accordingly, the fact that the Canadian Bitumen Operations had been operating a loss for at least three months would have been highly material to existing

and potential investors, lenders, and other creditors in assessing the timing, amount and uncertainty of future net cash inflows to Exxon.

57. Based on the foregoing, it is my opinion that Exxon was required to disclose in its 2015 Form 10-K the fact that the Canadian Bitumen Operations were at that time losing money, for the following reasons:

(a) As detailed above, FASB ASC 275 requires that if management knows, by the time the financial statements are issued, that a reasonable possibility exists that a significant estimate or estimates underpinning the recognition or measurement of element(s) of the financial statements is likely to change during the next 12 months and the effect of such change is material, management is required to make a thorough disclosure of the relevant facts in the financial statements. Such disclosures are called for when assessment of risks and circumstances indicate it is reasonably possible that there will be a material change in the estimates in the next year. Furthermore, ASC 275 requires that this disclosure be more than just a general statement but rather indicates that it must include an estimate of the effect of a change in a condition, situation, or set of circumstances that existed at the date of the financial statements and an indication that it is at least reasonably possible that a change in the estimate will occur in the near term.

(b) Given the significant losses incurred by the Canadian Bitumen Operations beginning no later than mid-November 2015, it was at least "reasonably possible," as that phrase is defined by ASC 275, at the time Exxon filed its 2015 Form 10-K, that the Company's estimates of future profitability, price, and cost levels would change within the next 12 months and would have a materially negative impact on, among other things, Exxon's net profits and proved bitumen reserve levels, both of which are highly material metrics to investors and other market participants.

(c) As detailed above, SEC Regulation S-K Item 303 requires a discussion of known trends or uncertainties that have had, or might reasonably be expected to have, a favorable or unfavorable material effect on revenue, operating income, or net income and the relationship between revenue and the costs of the revenue. Such MD&A disclosures are to include both a comprehensive discussion and analyses of known trends and uncertainties and not be merely a restatement of the financial statement information in a narrative form. The significant losses incurred by the Canadian Bitumen Operations beginning no later than mid-November 2015 clearly represented a known trend or uncertainty that could reasonably be expected to have a material unfavorable impact on revenues or income from continuing operations, and was thus required to be disclosed pursuant to Item 303.

(d) According to the U.S. Congress, one of the chief objectives of federal securities laws is full and fair disclosure. For example, in enacting the mandatory disclosure system under the Securities Exchange Act of 1934, the stated goal of Congress was to promote complete and accurate information in the capital markets: "[o]ne of the prime concerns of the exchanges should be to make available to the public, honest, complete, and correct information regarding the securities listed."[9] This is consistent with the provisions of SEC Regulation S-K Item 303 mandating that the MD&A section of registrant's financial statement should include information necessary to provide a full understanding of a registrant's financial condition, changes in financial condition and results of operations, including an analysis of known material trends.[10] Consistent with the above guidance, Exxon was required to disclose in its 2015 Form

[9] S. Rep. No. 73-1455, 73rd Cong., 2nd Sess., 1934 at 68.

[10] Interpretation: Commission Guidance Regarding Management's Discussion and Analysis of Financial Condition and Results of Operations, Securities and Exchange Commission 17 C.F.R. Parts 211, 231 and 241 (Release Nos. 33-8350, 34-48960; FR-72).

10-K that the Canadian Bitumen Operations had been operating at a loss for more than 3 months at the time the 2015 Form 10-K was filed with the SEC.

2. Disclosure Obligations Regarding Proved Reserve Calculations for the Kearl Project

58. As previously noted, ASC 932 mandates that, in order to qualify as proved reserves, the reserves must satisfy an "economic producibility" test, which assesses whether the revenues expected to be generated over the remaining life of the at-issue reserves exceed the anticipated costs of producing them. ASC 932 further requires that the sales price used to calculate expected future revenues "shall be the average price during the 12-month period prior to the ending date of the period covered by the report," and the anticipated costs of operation are calculated as the period-end cost levels applied to each year in the future for which production is expected.

59. Exxon filed its 2016 Form 10-K on February 22, 2017. In the 2016 Form 10-K, Exxon disclosed that "the entire 3.5 billion barrels of bitumen at [the] Kearl [project] did not qualify as proved reserves at year-end 2016."[11]

60. As detailed by Table 6 below, using the WCS Daily Spot Price (USD) in effect on the first day of each month, as reported by Bloomberg, the "average price during the 12-month period prior to the ending date of the period covered by the [2016 Form 10-K]" (*i.e.*, the 2016 calendar year) was $28.88 (USD/bbl). Thus, the 2016 Kearl De-Booking can be viewed as an acknowledgement by Exxon that the Kearl project did not satisfy ASC 932's proved reserves test at a 12-month average WCS price of $28.88 (USD/bbl).

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[11] This disclosure by Exxon is referred to herein as the "2016 Kearl De-Booking."

Table 6
2016 Average WCS Price (USD/bbl)

Month	WCS Daily Spot Price in Effect on First Day of Month (USD/bbl)	2016 Average WCS Price (USD/bbl)
January 2016	$23.79	
February 2016	$15.87	
March 2016	$22.00	
April 2016	$23.54	
May 2016	$32.57	
June 2016	$37.16	
July 2016	$35.19	
August 2016	$25.31	
September 2016	$29.11	
October 2016	$34.24	
November 2016	$32.27	
December 2016	$35.56	$28.88

61. Approximately one year earlier, Exxon maintained in its 2015 Form 10-K, filed on February 24, 2016, that all barrels of bitumen at the Kearl project did qualify as proved reserves at year-end 2015.

62. As detailed by Table 7 below, using the WCS Daily Spot Price (USD) in effect on the first day of each month, as reported by Bloomberg, the "average price during the 12-month period prior to the ending date of the period covered by the [2015 Form 10-K]" (*i.e.*, the 2015 calendar year) was $37.12 (USD/bbl). Thus, the Company's maintenance of all barrels of bitumen at the Kearl project on its proved reserve report was tantamount to an assertion by Exxon that the Kearl project *did* satisfy ASC 932's proved reserves test at a USD 12-month average WCS price of $37.12 (USD/bbl).

Table 7
2015 Average WCS Price (USD/bbl)

Month	WCS Daily Spot Price in Effect on First Day of Month (USD/bbl)	2015 Average WCS Price (USD/bbl)
January 2015	$37.27	
February 2015	$35.24	
March 2015	$36.01	
April 2015	$37.59	
May 2015	$50.40	
June 2015	$52.35	
July 2015	$44.96	
August 2015	$31.12	
September 2015	$31.31	
October 2015	$30.24	
November 2015	$31.39	
December 2015	$27.55	$37.12

63. Assuming for purposes of this analysis, that the 2015 Form 10-K and 2016 Form 10-K proved reserve calculations for the Kearl project were appropriately executed by Exxon, it can be concluded from the information described in paragraphs 59-62 above that the threshold 12-month average WCS price at which the bitumen at the Kearl project no longer qualified as proved reserves under ASC 932 is somewhere between $28.88 (USD/bbl) and $37.12 (USD/bbl).

64. One conservative method for estimating the actual threshold 12-month average WCS price at which the bitumen at the Kearl project no longer qualified as proved reserves under ASC 932 can be derived from an analysis of the “standardized measure of discounted future net cash flows related to proved oil and gas reserves” schedule disclosed in Imperial Oil’s 2015 Form 10-K, filed with the SEC on February 24, 2016.

65. Specifically, on page 79 of its 2015 Form 10-K, Imperial Oil disclosed that the standardized measure of future net cash flows related to all of its proved reserves at year-end 2015 was approximately $6.9 billion (CAD), which was down significantly from the 2014 figure

of $97.6 billion (CAD) for this same measurement. Because the "standardized measure of discounted future net cash flows related to proved oil and gas reserves" is calculated pursuant to identical guidelines as those prescribed by ASC 932's "economic producibility" test, this figure can reasonably be viewed as an indication that the revenues expected to be generated over the remaining life of ***all*** of Imperial Oil's proved reserves exceeded the anticipated costs of operation for such reserves over the same period by approximately $6.9 billion (CAD). In other words, at year-end 2015, Imperial Oil had a de-booking "buffer" of approximately $6.9 billion (CAD).

66. At year-end 2015, Imperial Oil reported approximately 3.515 billion bbl of proved bitumen reserves. Assuming, for the purpose of generating an overly conservative estimate for my analysis, that ***all*** of the $6.9 billion "buffer" described above was attributable to Imperial Oil's 3.515 billion bbl of proved bitumen reserves, most of which were attributable to the Kearl project, the amount of proved reserve "buffer" for Imperial Oil's proved bitumen reserves at year-end 2015 would have been approximately $1.97 (CAD/bbl) ($6.9 billion divided by 3.515 billion bbl = $1.97 bbl). Using the 2015 average CAD-to-USD exchange rate of 0.7748, as set forth on page 2 of Imperial Oil's 2015 Form 10-K, the $1.97 (CAD/bbl) "buffer" figure referenced above equates to approximately $1.52 (USD/bbl).

67. By subtracting the $1.52 (USD/bbl) 2015 proved reserve de-booking "buffer" amount described above from the 2015 12-month average WCS price of $37.12 (USD/bbl), it can be conservatively estimated that the minimum actual threshold 12-month average WCS price at which the bitumen at the Kearl project no longer qualified as proved reserves under ASC 932 was no lower than $37.12 - $1.52 = $35.60 (USD)/bbl.[12] Accordingly, it can reasonably be

[12] As noted above, this is a conservative estimate, due to the fact that the $6.9 billion (CAD) of future net cash flows described in paragraphs 65-66 above included net cash flows from ***all*** of Imperial Oil's proved reserves, not just the Kearl project – and not even just Imperial Oil's proved bitumen reserves. As a result, the actual amount of future net cash flows attributable to the Kearl project's proved reserves at year-end 2015 was necessarily an amount smaller than the $6.9 billion (CAD) described in paragraphs 65-66 above, which also means that the actual size of

assumed that Exxon knew, throughout 2016, that the Kearl project would not satisfy the SEC definition for proved reserves at year-end 2016 unless the 2016 12-month average WCS price was ***at least*** $35.61 (USD/bbl).

68. Table 8 below sets forth the WCS Daily Spot Price (USD) in effect on the first day of each month throughout 2016, as reported by Bloomberg; the year-to-date average WCS price, as of each month throughout 2016; and the minimum average WCS price needed over the remainder of the year in order for the Kearl project to continue to satisfy the SEC's definition for proved reserves, as of each month throughout 2016 (assuming, based on the foregoing analysis, that the minimum threshold 12-month average WCS price at which the Kearl project no longer qualified as proved reserves under ASC 932 was $35.60 (USD/bbl)).

Table 8
Minimum Average WCS Price Required to Avoid De-Booking

Month	WCS Daily Spot Price in Effect on First Day of Month (USD/bbl)	Year-to-Date Average WCS Price (USD/bbl)	Minimum Average WCS Price Needed Over Remainder of Year to Avoid De-Booking (USD/bbl)
January 2016	$23.79	$23.59	$36.68
February 2016	$15.87	$19.83	$38.77
March 2016	$22.00	$20.55	$40.63
April 2016	$23.54	$21.30	$42.77
May 2016	$32.57	$23.55	$44.22
June 2016	$37.16	$25.82	$45.40
July 2016	$35.19	$27.16	$47.44
August 2016	$25.31	$26.93	$52.97
September 2016	$29.11	$27.17	$60.93
October 2016	$34.24	$27.88	$74.27
November 2016	$32.27	$28.28	$116.27
December 2016	$35.56	$28.88	n/a

the proved reserves "buffer" for the Kearl project at year-end 2015 necessarily would have been an amount smaller than $1.52 (USD/bbl).

69. As Table 8 illustrates, it would have been apparent to Exxon at the beginning of 2016 that, absent an extraordinary (and by Imperial Oil's own forecasted estimates, unexpected)[13] rise in the price of oil, the Kearl project would not satisfy the SEC definition of proved reserves at year-end 2016. Furthermore, that fact would have only become more and more undeniable as the year progressed. However, Exxon's disclosures throughout 2016 did not accurately reflect this awareness.

70. For example, a disclosure made by Exxon in its 2015 Form 10-K, which was filed on February 24, 2016, stated, in relevant part, that "[w]hen crude oil and natural gas prices are in the range seen in late 2015 and early 2016 for an extended period of time . . . certain quantities of oil and natural gas, such as oil sands operations in Canada . . . could temporarily not qualify as proved reserves." As illustrated by Table 8, at the time Exxon made this statement, the year-to-date average WCS price was just $19.83 (USD/bbl), and Exxon knew that the Kearl project would only satisfy the SEC definition for proved reserves at year-end 2016 if the average WCS price over the remainder of the year was $38.77 (USD/bbl) – or nearly ***double*** the year-to-date average.

71. In a news release on October 28, 2016, Exxon similarly announced: "If the average prices seen during the first nine months of 2016 persist for the remainder of the year, under the SEC definition of proved reserves, certain quantities of oil, such as those associated with the Kearl oil sands operations in Canada, will not qualify as proved reserves at year-end 2016." As illustrated by Table 8, at the time Exxon made this statement, the year-to-date average WCS price was just $27.88 (USD/bbl), and Exxon knew that the Kearl project would

[13] Imperial Oil's 2015 Report 51-101F1, Item 3.2, contained forecasted future WCS benchmark average yearly prices for each year until 2025. In this disclosure, Imperial Oil indicated that its WCS benchmark price forecast for 2016 was $43.76 (CAD/bbl) – or $33.91 (USD/bbl), using the 0.7748 exchange rate described in paragraph 66 above.

only satisfy the SEC definition for proved reserves at year-end 2016 if the average WCS price over the remainder of the year was $74.27 (USD/bbl) – which was almost ***three times*** the year-to-date average.

72. Based on the foregoing, it is my opinion that Exxon's 2015 Form 10-K and 2016 Form 10-Q reports violated GAAP, including FASB ASC 275, ASC 932, and SEC Regulation S-K Item 303 requirements, by failing to provide more detailed and truthful disclosures concerning the likelihood that the Kearl project would not satisfy the SEC definition for "proved reserves" at year-end 2016, for the following reasons:

(a) ASC 932 requires that, when adverse events cause significant downward estimates in proved reserves, the information must be conveyed to financial statement users at the earliest possible time. Waiting until the subsequent annual financial reporting date is not acceptable. Exxon knew about the virtually certain need to de-book the Kearl project's proved reserves before it issued its 2015 Form 10-K on February 24, 2016, but the Company improperly failed to warn investors of the near certainty of the future de-booking at that time.

(b) Moreover, while formal reserve reports are not a mandated component of interim reports (such as Form 10-Q reports), when adverse events that significantly affect proved reserve quantities occur, disclosure regarding such revisions *must be* included in interim reports. According to ASC 932-270-50-1:

> The disclosures set forth in Subtopic 932-235 are not required in interim financial reports. However, interim financial reports shall include information about a major discovery or other favorable or adverse event that causes a significant change from the information presented in the most recent annual financial report concerning oil and gas reserve quantities.

(c) Notwithstanding this clear guidance from ASC 932-270-50-1, Exxon failed to adequately alert investors as to the near certainty regarding the Kearl project's future

de-booking in its 2016 Form 10-Q filings, even as continually low oil prices made the de-booking more of a virtual certainty with each passing month throughout 2016.

(d) Given the facts detailed above, Exxon clearly would have known at the time it filed its 2015 Form 10-K and 2016 Form 10-Q reports that the Company's estimates of proved reserves were likely to change within the next 12 months, and would have a materially negative impact on Exxon's worldwide proved reserve levels. As such, Exxon was required to disclose as much to investors pursuant to ASC 275.

(e) Notwithstanding the FASB mandates in ASC 275 and ASC 932, detailed above, the objective of general purpose financial reporting is to provide information about a reporting entity that is useful to existing and potential investors, lenders, and other creditors in assessing the timing, amount and uncertainty of future net cash inflows to the entity. It is critical that information which has a material effect on the estimation of future cash flows be communicated publicly at the earliest possible date. For companies engaged in oil and gas producing activities, disclosures regarding the proved oil and gas reserves is essential in estimates of future cash flows and, therefore, any material changes in reserves estimates must be disclosed at the earliest possible date. Overstatement of proved oil and gas reserves may significantly impact the ability of existing and potential investors, lenders, and other creditors to estimate the timing, amounts and uncertainties of future cash flows. Exxon's Canadian bitumen reserves constituted a material portion of Exxon's total proved reserves at year-end 2015, representing approximately 31% of Exxon's total liquids proved reserves and 18% of the Company's combined liquids and natural gas worldwide proved reserves. Roughly 75% of the 4.56 billion bbl of proved Canadian bitumen reserves Exxon reported in its 2015 Form 10-K were attributable to the Kearl project, with the remainder at Cold Lake. Accordingly, disclosure of the Kearl project's likely de-booking at year-end 2016 would have been highly material to

existing and potential investors, lenders, and other creditors in assessing the timing, amount and uncertainty of future net cash inflows to Exxon. As such, Exxon's failure to provide more detailed and truthful disclosures concerning the likelihood that the Kearl project would not satisfy the SEC definition for "proved reserves" at year-end 2016 violated its general financial reporting obligations.

(f) Finally, SEC Regulation S-K Item 303 requires comprehensive MD&A discussion and analyses of known trends or uncertainties that might reasonably be expected to have a material unfavorable effect on net income. Given the facts detailed above, Exxon clearly would have known at the time it filed its 2015 Form 10-K and 2016 Form 10-Q reports that the Company's estimates of the Kearl project's proved reserves were likely to negatively change within the next 12 months and the change would have a materially negative impact on their earnings and Kearl project-related assets. Exxon violated SEC Regulation S-K Item 303 by failing to acknowledge the precarious situation regarding the Kearl project's proved reserves and assets in its 2015 Form 10-K and Form 10-Q filings for the first three quarters of 2016.

3. Disclosure Obligations Regarding Exxon's Failure to Include a "Carbon Proxy" in Connection with its Canadian Bitumen Operations

73. For purposes of this declaration, I have reviewed certain information available from the public docket for *People of the State of New York v. PricewaterhouseCoopers LLP, et al.*, Index No. 451962/2016 (N.Y. Sup. Ct., N.Y. Cty.), including the Memorandum of Law in Opposition to Exxon's Motion to Quash and in Support of the Office of the Attorney General's Cross-Motion to Compel, dated June 2, 2017 (Dkt. No. 168) (OAG Brief), the Affirmation of John Oleske in Opposition to Exxon's Motion to Quash and in Support of the Office of the Attorney General's Cross-Motion to Compel, dated June 2, 2017 (Dkt. No. 169) (Oleske Affirmation), and the exhibits attached to the Oleske Affirmation (Dkt. Nos. 170-202) (Oleske

Exhibits). In so doing, I have accepted as true the sworn testimony set forth in the Oleske Affirmation, which was provided under penalty of perjury.

74. As detailed in the OAG Brief, the Oleske Affirmation and the Oleske Exhibits, Exxon made numerous public statements during the Class Period representing "to investors that in its economic decision-making, including its investment decisions and asset valuations, the company applies a 'proxy cost' of [greenhouse gas ('GHG')] emissions that reasonably approximates the range of potential future government actions with respect to climate change." OAG Brief at 3; *see also* Oleske Affirmation at ¶¶6-19, 47; Oleske Exhibits 1-2, 12.

75. For example, in 2014, Exxon released a report entitled "Energy and Climate," in which the Company stated: "However, for our Outlook we use a cost of carbon as a proxy to model a wide variety of potential policies that might be adopted by governments to help stem GHG emissions." The report also stated: "in the OECD nations [which include Canada and the United States], we apply a proxy cost that is about $80 per ton in 2040." In addition, Exxon stated in the same report: "This GHG proxy cost is integral to ExxonMobil's planning."[14]

76. Among other things, the OAG Brief and the Oleske Affirmation assert that, contrary to Exxon's representations to investors, the Company did not apply its publicly stated GHG "proxy cost" to Exxon's investment and asset valuation processes concerning the Canadian Bitumen Operations. *See* OAG Brief at 7; Oleske Affirmation at ¶¶29-33. Specifically, the Oleske Affirmation states that "evidence indicates that Exxon decided in the fall of 2015 to abandon the proxy-cost figures applicable to Alberta projects that were set out in its internal policies, and decided instead to apply the current, much lower GHG tax that existed under Alberta law at that time." Oleske Affirmation at ¶30.

[14] http://cdn.exxonmobil.com/~/media/global/files/energy-and-environment/report---energy-and-climate.pdf.

77. In addition, the Oleske Affirmation provides testimony regarding the details of Exxon's decision to "abandon the proxy-cost figures applicable to Alberta projects." Oleske Affirmation at ¶30. Specifically, the Oleske Affirmation states that "The proxy cost analysis set out in Exxon's internal policies required the incorporation of an escalating GHG cost, reaching $80/ton of carbon dioxide (or CO2 equivalent in other GHGs) by 2040, into the company's economic forecasting for purposes of corporate decision-making," but that Exxon, in fact, only applied the Alberta GHG tax then in place "and held that figure flat indefinitely into the future" in a manner "resulting in an effective cost of less than $4/ton." Oleske Affirmation at ¶31.

78. By applying only a portion of an ***already existing*** GHG tax, and holding "that figure flat indefinitely into the future," Exxon's actual practices did not correspond to its representations to investors. To the contrary, as noted above, Exxon's representations to investors indicated that the Company applied a GHG or carbon "proxy cost" as a means for "model[ing] a wide variety of ***potential policies*** that might be adopted by governments to help stem GHG emissions" and specifically stated that "in the OECD nations [which include Canada], we [the Company] apply a proxy cost that is ***about $80 per ton*** in 2040" (emphasis added).[15]

79. According to a 2014 study from IHS,[16] the average total amount of GHGs resulting from the mining and use of bitumen from Canadian oil sands operations is roughly 92 kg CO2e/bbl (or 0.092 metric tons of GHG emissions/bbl). Thus, the application of an additional $80/ton GHG "proxy cost" to the Canadian Bitumen Operations would have resulted in an additional cost of approximately $5.70 (USD/bbl) – clearly a material amount. Indeed, even the application of an additional $20/ton GHG "proxy cost," a mere fraction of the $80/ton

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[15] http://cdn.exxonmobil.com/~/media/global/files/energy-and-environment/report---energy-and-climate.pdf, (p.5).

[16] "Study Says 45 Per Cent of U.S. Oil Supply of Similar GHG Intensity as Oil Sands," *Daily Oil Bulletin*, 2 June 2014.

GHG "proxy cost" referenced in ¶31 of the Oleske Affirmation, would have resulted in an additional cost of approximately $1.43 (USD/bbl).

80. Moreover, the material impact of Exxon's failure to incorporate its publicly stated GHG "proxy cost" into calculations concerning the investment and asset valuation processes for the Canadian Bitumen Operations is further confirmed by the sworn testimony of the Oleske Affirmation, which states that "according to evidence reviewed by OAG, [actual application of Exxon's publicly stated GHG 'proxy cost'] may have rendered at least one of its major [Canadian] oil sands projects unprofitable over the life of the project." Oleske Affirmation at ¶29.

81. Based on the foregoing, and accepting the sworn testimony set forth in the Oleske Affirmation as true, it is clear that, from at least "the fall of 2015" on, Exxon's investment and asset valuation processes for the Canadian Bitumen Operations were not consistent with the Company's public representations regarding its supposed use of a GHG "proxy cost" in connection with such processes. As a result, it is my opinion that, beginning at least with Exxon's 2015 Form 10-K and continuing throughout the Class Period, Exxon's filings with the SEC violated fundamental GAAP guidance as well as ASC 275, by failing to disclose that, contrary to the Company's statements to investors, Exxon did not incorporate a GHG "proxy cost" into the Company's calculations concerning its investment and asset valuation processes for the Canadian Bitumen Operations, for the following reasons:

(a) One of the most basic tenants of financial reporting and disclosure is that the information presented must be truthful. According to established FASB guidance: "To be useful, financial information not only must represent relevant phenomena, but it also must faithfully represent the phenomena that it purports to represent. To be a perfectly faithful

representation, a depiction would have three characteristics. It would be complete, neutral, and free from error." (SFAC No. 8 p. 17).

(b) Moreover, according to the FASB: "Free from error means there are no errors or omissions in the description of the phenomenon, and the process used to produce the reported information has been selected and applied with no errors in the process." (SFAC No. 8 p. 17).

(c) By publicly indicating that a GHG "proxy cost" was incorporated into Exxon's estimate of current and future costs, while in fact Exxon did not do so with regard to the Canadian Bitumen Operations, the Company's 2015 Form 10-K and 2016 Form 10-Q reports were not representationally faithful, and therefore, violated fundamental FASB guidance.

(d) Exxon's failure to truthfully disclose that the Company did not incorporate a GHG "proxy cost" into Exxon's calculations concerning its investment and asset valuation processes for the Canadian Bitumen Operations was a clear violation of ASC 275.

4. Exxon Materially Misstated its Financial Statements by Failing to Incorporate a GHG "Proxy Cost" into the Company's Proved Reserves and Asset Impairment Calculations for the Canadian Bitumen Operations

82. As set forth above, the Oleske Affirmation establishes that, contrary to numerous representations Exxon made to investors, from at least "the fall of 2015" on, the Company did not apply its publicly stated GHG "proxy cost" to Exxon's investment and asset valuation processes concerning the Canadian Bitumen Operations.

83. In addition, the Oleske Affirmation states that "evidence to date indicates no attempt at all, by Exxon or by PwC, to incorporate a proxy cost of GHGs into the economic models of cash flows used in determining whether a trigger for impairment testing existed or whether Exxon's assets were actually impaired prior to 2016. To the contrary, these documents

indicate that Exxon and PwC only began incorporating proxy cost assumptions into some of Exxon's impairment-related accounting analyses in 2016." Oleske Affirmation at ¶49.

84. As noted in paragraph 79 above, the costs associated with actual application of Exxon's publicly stated GHG "proxy cost" to its Canadian Bitumen Operations would have been significant, given that a $80/ton GHG "proxy cost" would have equated to an additional cost of approximately $5.70 (USD/bbl), and even just a $20/ton GHG "proxy cost" would have equated to an additional cost of approximately $1.43 (USD/bbl). These numbers are particularly significant in light of my conclusion above that the Kearl project was no more than $1.52 (USD/bbl) away from no longer qualifying as a proved reserve at year-end 2015, without the application of any GHG "proxy cost."

85. Moreover, as also noted above, the material impact of Exxon's failure to incorporate its publicly stated GHG "proxy cost" into applicable accounting calculations concerning the Canadian Bitumen Operations is further confirmed by the sworn testimony of the Oleske Affirmation, which states that "according to evidence reviewed by OAG, [actual application of Exxon's publicly stated GHG proxy cost] may have rendered at least one of its major [Canadian] oil sands projects unprofitable over the life of the project." Oleske Affirmation at ¶29. This statement is also consistent with my conclusion above that the Kearl project was no more than $1.52 (USD/bbl) away from no longer qualifying as a proved reserve at year-end 2015.

86. Based on the foregoing, and accepting the sworn testimony set forth in the Oleske Affirmation as true, it is clear that, throughout the Class Period, Exxon failed to incorporate a GHG "proxy cost" into the Company's proved reserve and/or asset impairment calculations for

the Canadian Bitumen Operations.[17] As a result, it is my opinion that, throughout the Class Period, Exxon's filings with the SEC violated fundamental GAAP guidance as well as numerous provisions appearing in FASB ASC 360, ASC 932, and SEC Regulation S-X Rule 4-10 requirements, for the following reasons:

(a) The definition of proved reserves is established by the SEC in Regulation S-X Rule 4-10 and adopted by the FASB in ASC 932-10-S99-1. One of the most critical aspects in the definition of proved reserves is, in order to qualify as such, the quantities of oil and gas reserves must be *economically producible* under current economic conditions, *i.e.*, conditions existing as of the financial statement date. Proper determination of current costs is integral to the determination of economically producibility. GHG "proxy cost" represents a current and future cost of exploring, developing and producing proved reserves. Failure to include GHG "proxy costs" results in (at a minimum), understatement of the cost of producing proved reserves, overstatement of future net cash inflows from producing proved oil and gas reserves and, thus, overstatement of proved reserve quantities.

(b) Numerous accounts and estimates were affected by Exxon's failure to include the clearly material GHG "proxy cost" in the Company's investment and asset valuation processes, as represented to investors. Indeed, Exxon's failure to do so clearly would have affected not only reserve estimates but also operating costs, depreciation, depletion and amortization (DD&A), liabilities, impairment, asset retirement obligations and earnings, among other figures and estimates contained in the Company's financial statements.

[17] This conclusion is based on the Oleske Affirmation's sworn testimony that, at least prior to 2016, Exxon made no attempt to incorporate a GHG "proxy" into any of its asset impairment calculations, and at least after "the fall of 2015" Exxon failed to incorporate a GHG "proxy" into its asset valuation processes for the Canadian Bitumen Operations. Consequently, each of Exxon's various filings with the SEC throughout the Class Period failed to incorporate a GHG "proxy" into either the Company's asset impairment determinations concerning the Canadian Bitumen Operations or its proved reserves calculations concerning the Canadian Bitumen Operations, or both.

(c) Specifically, ASC 360-10-35-29 defines expected future cash flows used to test the recoverability of a long-lived asset as follows:

> Estimates of future cash flows used to test the recoverability of a long-lived asset (asset group) shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset (asset group). Those estimates shall exclude interest charges that will be recognized as an expense when incurred. (ASC 360-10-35-29).

(d) The FASB goes on to state that, in applying the recoverability test, the estimates are to include all available evidence including the entity's own assumptions about the use of the asset, including information communicated to others.

> Estimates of future cash flows used to test the recoverability of a long-lived asset (asset group) shall incorporate the entity's own assumptions about its use of the asset (asset group) and shall consider all available evidence. The assumptions used in developing those estimates shall be reasonable in relation to the assumptions used in developing other information used by the entity for comparable periods, such as internal budgets and projections, accruals related to incentive compensation plans, or information communicated to others. (ASC 360-10-35-30).

(e) Consistently, Brady, *et al.*, observe that "proper determination of expected future cash flows for the Step 1 impairment test incorporates entity-specific assumptions" and management's best estimates in formulating projections of future costs:

> **Costs**. Future cost projections should be management's best estimates of the future capital expenditures, operating costs, and, perhaps ARO costs directly associated with the impaired asset group. These costs should also have a high correlation with the future operating and capital expenditure assumptions management uses in its long-range budgeting process. (Brady, *et al.,* p. 326).

(f) Clearly GHG "proxy costs" are current and future costs of oil and gas exploration and production and must be included as production costs in the determination of current cost and in the estimation of future cost projections. Moreover, Exxon affirmatively represented to investors that it used such costs in all of its "own assumptions about its use of the

asset." (ASC 360-10-35-30); Oleske Affirmation at ¶16 ("price of carbon gets put into all of our economic models").

(g) Accordingly, Exxon violated the above ASC provisions and guidance from Brady, *et al.*, by failing to incorporate a GHG "proxy" into its asset impairment calculations.

(h) Oil and gas reserves represent the primary source of future cash flow for an oil and gas producing company and affect virtually every aspect of financial accounting and reporting. The extensive use of reserve information in financial accounting and reporting is addressed in detail by my book, *Fundamentals of Oil and Gas Accounting* 6th ed., PennWell Publishing (2016), which states as follows:

> For example, reserve information affects financial accounting in the following ways:
>
> - The decision as to whether a well is classified as exploratory or development is based on the assignment of proved reserves.
> - The treatment of certain costs as capital versus expense is determined based on whether additional quantities of proved reserves are expected to result from the expenditure.
> - Proved and proved developed reserves are used in computing unit-of-production depreciation, depletion, and amortization.
> - Classification of property acquisition costs as being unproved versus proved is based on the discovery of proved reserves.
> - Certain transactions require that the fair value of oil and gas properties be estimated (*i.e.*, asset swaps, business combinations). Reserves are the foundation of any estimation of fair value for an oil and gas property.
> - Impairment of oil and gas properties by companies using either the successful efforts or the full cost method.
> - The SEC requires public companies to make extensive disclosures of reserve information, including reserve quantities and a standardized measure of reserve values.

(Wright, p. 77).

(i) Similarly, Brady, *et al.*, current and former audit and assurance partners at Exxon's independent auditing firm, PwC, describe the extensive use of reserve information in financial reporting as follows:

> E&P financial reporting is highly dependent on proved reserves information as indicated in the following list:
>
> - Under successful efforts accounting, exploratory well costs are capitalized only if they result in finding proved reserves (Chapter 6).
> - Capitalized costs of proved properties are amortized on a units-of-production basis using the ratio of volumes currently produced to the sum of those volumes and remaining proved reserves (Chapter 17).
> - Proved properties' net capitalized costs are limited to certain computations of value based on reserves (including proved reserves (Chapters 18 and 19).
> - Reserves (including proved reserves) are used in determining whether and to what extent a gain is recognized in certain conveyances of oil and gas properties (Chapters 21 through 23).
> - Reserves (including proved reserves) are used to determine the fair value of oil and gas properties in business combinations (Chapter 30).
> - Public companies must disclose certain supplemental unaudited information on the proved reserves volumes (Chapter 28).

(Brady, *et al.*, p. 286).

(j) Brady, *et al.*, go on to describe a number of ways that reserve information is used in addition to the list cited above, including:

> - Historical financial and income tax reporting for amortization of certain costs.
> - Determination of impairment of proved properties in accordance with ASC 360 (Chapter 18) and calculation of the full cost ceiling test (Chapter 19).

- Development of long-range plans and budgets.
- Management decisions regarding field development and reservoir management.
- Bank loans and lines of credit collateralized by future production.
- Valuation of developed oil and gas properties, or valuation of a company being considered for acquisition or divestment.
- Regulatory hearings or litigation.

(Brady, *et al.*, p. 300).

(k) Given the pervasive use of oil and gas reserves information by existing and potential investors, lenders, and other creditors to assess the timing, amount and uncertainty of future net cash inflows to oil and gas producing companies, any material misstatement in the estimation of future cost projections undermines the estimation of proved reserves and therefore the ability of financial statement users to estimate the prospects for future net cash inflows. Further, existing and potential investors, lenders, and other creditors cannot rely on the provided information to evaluate the resources of the entity, claims against the entity, and how efficiently and effectively the entity's management and governing board have discharged their responsibilities to use the entity's resources.

(l) Moreover, the material impact that would have resulted from Exxon's actual incorporation of a GHG proxy cost into its asset impairment and proved reserve calculations for the Canadian Bitumen Operations is further confirmed by the sworn testimony of the Oleske Affirmation, which states that "according to evidence reviewed by OAG, [actual application of Exxon's publicly stated GHG proxy cost] may have rendered at least one of its major [Canadian] oil sands projects unprofitable over the life of the project." Oleske Affirmation at ¶29. As noted above, this statement is also consistent with my conclusion that the

Kearl project was no more than $1.52 (USD/bbl) away from no longer qualifying as a proved reserve at year-end 2015, without the application of any GHG "proxy cost."

B. The Rocky Mountain Dry Gas Operations

87. As noted above, the 2016 Dry Gas Impairment Charge was first disclosed by Exxon on January 31, 2017, and subsequently confirmed in the Company's 2016 Form 10-K, dated February 22, 2017. In the 2016 Form 10-K, Exxon states that the "asset impairment charge of $2,027 million mainly related to dry gas operations with undeveloped acreage in the Rocky Mountains region of the U.S." To date, Exxon has not disclosed additional details regarding the specific "dry gas operations with undeveloped acreage" at issue in the 2016 Dry Gas Impairment Charge. However, based on public statements by Exxon and its wholly-owned subsidiary, XTO Energy Inc., Exxon's Rocky Mountain dry gas operations were primarily limited throughout the Class Period to certain basins in Colorado, New Mexico, Utah and Wyoming (Rocky Mountain Dry Gas Regions).

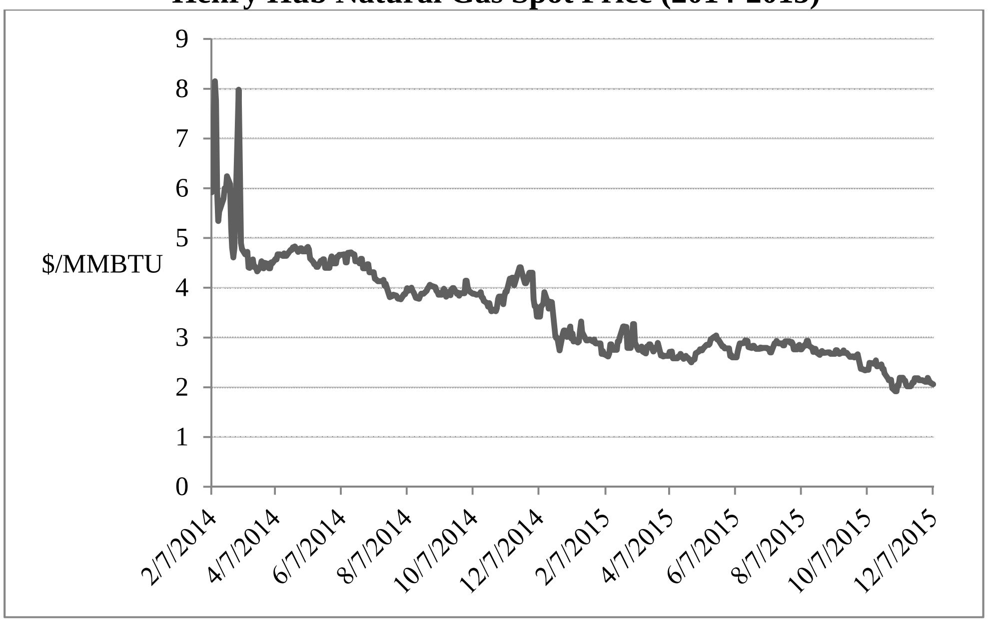
1. An Impairment Trigger Event Concerning Exxon's Rocky Mountain Dry Gas Operations Was Present by at Least Year-end 2015

88. By at least year-end 2015, numerous significant red flags, complications and adverse business conditions had arisen or continued to persist concerning Exxon's Rocky Mountain dry gas operations.

89. First, beginning in early-2014, the Henry Hub natural gas spot price (the most commonly used benchmark price for U.S. natural gas operations, including those in the Rocky Mountain Dry Gas Regions) commenced a prolonged decline that continued throughout most of 2014 and 2015. Specifically, on February 10, 2014, the Henry Hub natural gas spot price was

\$8.15/MMBTU.[18] By December 31, 2014, however, the Henry Hub natural gas spot price had fallen to \$3.14/MMBTU, a decline of more than 61% over the course of just less than 11 months. The Henry Hub natural gas spot price continued to fall throughout 2015, reaching a price of \$2.28/MMBTU by December 31, 2015. This represents a decline of more than 72% from the \$8.15/MMBTU reported on February 10, 2014. This prolonged price decline is illustrated in Figure 2:

FIGURE 2
Henry Hub Natural Gas Spot Price (2014-2015)



90. Brady, *et al.*, observe that ASC 360-10-35-21 requires that management evaluate the possible impairment of oil and gas properties, "if events or circumstances indicate that the carrying value may not be recoverable. Impairment indicators for oil and gas properties can include: Lower than expected future oil and gas prices (such as prices used by management in evaluating whether to develop or acquire properties)." (Brady, *et al.*, p. 322). The 61% decline in prices from February 10, 2014 to December 31, 2014 and the continued decline through

[18] All Henry Hub natural gas spot price information included in this declaration is provided in units of USD per millions of British thermal units, or \$/MMBTU, and based on pricing information reported by Thomson Reuters.

December 31, 2015 surely would have been observed by Exxon's management and taken into consideration when "evaluating whether to develop or acquire properties."

91. In Exxon's 2015 Form 10-K, the Company stated that it "does not view temporarily low prices or margins as a trigger event for conducting impairment tests." It is my opinion, however, that the Henry Hub price decline described in paragraph 89 above, was not a "temporarily low price," but rather, "a significant decrease in the market price," as contemplated by ASC 360-10-35-21 (as discussed in paragraph 29 above).

92. Another factor to be considered in evaluating potential impairment triggers for Exxon's Rocky Mountain dry gas operations is the activity of other operators in the Rocky Mountain Dry Gas Regions. Throughout 2014 and 2015, a number of these operators demonstrated clear signs of distress in response to the slumping natural gas prices.

93. For example, several companies with comparable natural gas operations in the Rocky Mountain Dry Gas Regions took impairment charges during 2014 and 2015 due to the decline in prices, including the following: Ultra Petroleum Corp. (Ultra Petroleum), Vanguard Natural Resources, LLC (Vanguard) and Breitburn Energy Partners LP (Breitburn) (collectively, Other Rocky Mountain Dry Gas Operators). A review of the 2014 Form 10-K and 2015 Form 10-K filings for each of the Other Rocky Mountain Dry Gas Operators reveals that declining prices were a primary factor for impairment:

- Ultra Petroleum tested its assets for impairment, and, "based upon the average of quoted market prices in effect on the first day of the month for the preceding twelve month period at December 31, 2015," revealed that their assets were impaired by $3.1 billion.

- Vanguard reported impairments of $1.8 billion in its 2015 Form 10-K, specifically noting that the most significant factors causing the write-down included "declining oil and natural gas prices."

- Breitburn took a $2.4 billion impairment charge in its 2015 Form 10-K, including $147.9 million attributable to the Rocky Mountains region, "primarily due to the

impact that the prolonged drop in commodity prices had on [its] projected future net revenues."

94. The impact of declining prices in the Rocky Mountain Dry Gas Regions was also reported in a March 24, 2015 *Platts Gas Daily* article, which stated that well starts in the top-five natural gas producing basins in the Rocky Mountains "have lagged last year's levels by about 25% as low commodity prices have strained drilling economics in the region . . . [t]he main causes have been lower gas and crude prices this year."

95. In my opinion, the negative business facts, trends and conditions described in paragraphs 88-94 above, all of which were occurring or persisting at year-end 2015 and before Exxon's 2015 Form 10-K was prepared and filed, constituted an impairment "trigger event" pursuant to FASB ASC 360-10, as described in paragraph 29 above. Accordingly, Exxon should have tested the Rocky Mountain dry gas operations at issue in the 2016 Dry Gas Impairment Charge for potential impairment by no later than the accounting period ending on December 31, 2015.

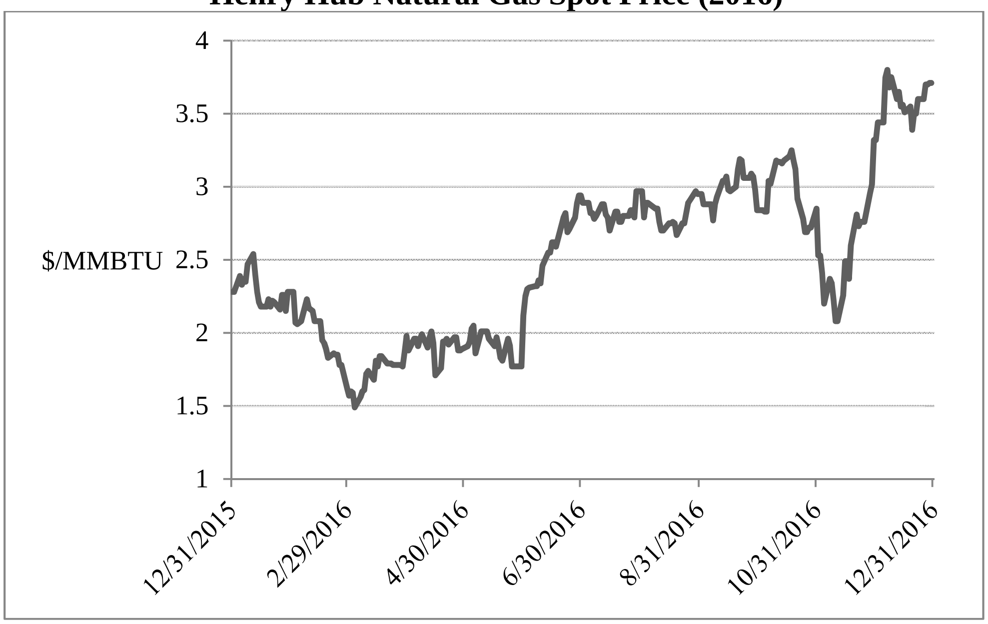
2. Exxon's Rocky Mountain Dry Gas Operations Were Impaired by at Least Year-End 2015

96. Moreover, had Exxon conducted such a test, it is my opinion that the Company should have concluded that these assets were subject to an impairment charge pursuant to FASB ASC 360-10 by no later than the accounting period ending on December 31, 2015. This opinion is based largely upon a comparison of several key impairment-related factors at year-end 2016 (when Exxon expressly acknowledged in its 2016 Form 10-K that the Rocky Mountain dry gas operations at issue in the 2016 Dry Gas Impairment Charge were impaired) to the same set of factors at year-end 2015, as well as other qualitative factors, as detailed below.

97. First, as noted above, the Henry Hub natural gas spot price steadily declined throughout most of 2014 and 2015, declining all the way from \$8.15/MMBTU on February 10,

2014, to $2.28/MMBTU by December 31, 2015. However, midway through 2016, the Henry Hub natural gas price began to rebound, and it continued to increase throughout the second half of 2016, ultimately reaching $3.71/MMBTU by December 30, 2016, which marked the close of the reporting period in which Exxon recorded the 2016 Dry Gas Impairment Charge. The price on December 30, 2016 represented ***an increase of more than 62% from December 31, 2015***, the final day of the 2015 fiscal year in which Exxon recorded no asset impairment related to its dry gas operations. The price increase over the course of the 2016 calendar year is demonstrated in Figure 3 below:

FIGURE 3
Henry Hub Natural Gas Spot Price (2016)



98. Second, as detailed in Table 9 below, an analysis of Exxon's average gas production costs for 2015 and 2016, as well as those for the Other Rocky Mountain Dry Gas Operators, supports the conclusion that production costs for Rocky Mountain dry gas operations were generally the same or lower at year-end 2016 than at year-end 2015:

TABLE 9
Reported Production Costs

Company	2015	2016
Exxon (USD/boe)	$13.16	$11.18
Breitburn (USD/boe)	$8.54	$8.27
Ultra Petroleum (USD/mcfe)	$3.28	$1.73
Vanguard (USD/mcfe)	$0.96	$1.01

99. Third, as detailed in paragraphs 92-93 above and summarized in Table 10 below, a number of the Other Rocky Mountain Dry Gas Operators took significant impairment charges during 2014 and 2015, due primarily to the decline in natural gas prices:

TABLE 10
Year-End Impairment Charges (USD)

Company	2014	2015
Exxon	n/a	n/a
Breitburn	$150 million	$2.4 billion
Ultra Petroleum	n/a	$3.15 billion
Vanguard	$230 million	$1.84 billion

100. Fourth, numerous operators began divesting of their dry gas assets in 2014 and 2015. Divestitures were made by a number of companies, including Encana Corp ($1.8 billion divested in March 2014), Royal Dutch Shell ($925 million divested in August 2014), and Anadarko ($700 million divested in April 2015).

101. Based on the above facts, it is my opinion that, to the extent the Rocky Mountain dry gas operations at issue in the 2016 Dry Gas Impairment Charge were impaired pursuant to FASB ASC 360-10 at year-end 2016, as Exxon affirmatively acknowledged in its 2016 Form 10-K, those same assets ***must*** have been impaired pursuant to FASB ASC 360-10 by no later than year-end 2015. As such, Exxon should have taken an impairment charge related to those assets by at least the time the Company disclosed its fourth quarter and full-year financial results for 2015. Moreover, it is also my opinion that had the proper impairment charge been taken at year-

end 2015, it clearly would have been material to investors, given the size of the asset impairment charge Exxon ultimately took at year-end 2016 (approximately $2 billion on a post-tax basis).

102. The materiality of Exxon's failure to take the appropriate asset impairment charge at year-end 2015 is further confirmed by the fact that, had the appropriate impairment charge been taken at year-end 2015, it would have caused Exxon to fail to meet analysts' consensus expectations for the Company's 2015 year-end earnings per share (EPS). As noted in paragraph 39 above, the SEC's guidance on materiality in SAB 99 recognizes that qualitative factors must be considered in any materiality analysis, and that such factors can have the effect of causing even quantitatively small misstatements to be rendered material. Included among the important qualitative factors specifically identified by SAB 99 is the consideration of "[w]hether the misstatement hides a failure to meet analysts' consensus expectations for the enterprise."[19] Based on the analysis described in the following paragraph, it is my opinion that Exxon's failure to take an appropriate asset impairment charge at year-end 2015 constituted a misstatement that served to hide to the Company's "failure to meet analysts' consensus expectations for the enterprise."

103. According to information reported by Thomson Reuters, analysts' consensus expectations for Exxon's 2015 full year EPS were $3.82/share. According to Exxon's 2015 Form 10-K, the Company's reported 2015 full year EPS was $3.85/share, or $0.03/share above analysts' consensus expectations. Using Exxon's reported 2015 net income of $16.15 billion, I was able to estimate Exxon's 2015 full-year implied weighted average common shares outstanding as 4.195 billion shares. Using this information, I was able to determine that Exxon would have failed to meet analysts' consensus expectations for the Company's 2015 full-year EPS if Exxon had recorded an asset impairment charge of $167 million or greater at year-end

[19] SEC Staff Accounting Bulletin No. 99.

2015. Given that the asset impairment charge ultimately taken by Exxon at year-end 2016 exceed $2 billion after tax, it is my opinion that, if Exxon had taken the proper impairment charge at year-end 2015, the amount charged would have certainly been greater than $167 million, likely by a significant amount. As such, it is my opinion that Exxon's failure to take an appropriate asset impairment charge at year-end 2015 constituted a misstatement that served to hide to the Company's "failure to meet analysts' consensus expectations for the enterprise," as contemplated by SAB 99.

104. Based on the foregoing, it is my opinion that Exxon's 2015 Form 10-K violated GAAP by failing to record an appropriate asset impairment charge related to Exxon's Rocky Mountain dry gas operations. Moreover, it is also my opinion that each of Exxon's 2016 Form 10-Q reports also violated GAAP by failing to record an appropriate asset impairment charge related to Exxon's Rocky Mountain dry gas operations.

105. My opinions in paragraphs 101-104 above are further bolstered by the fact that, as detailed in the Oleske Affirmation, evidence indicates that prior to 2016 (the same year in which Exxon took the 2016 Dry Gas Impairment Charge) "Exxon failed to apply a proxy cost of GHGs in determining whether its long-lived assets, such as oil and gas reserves and resources, were impaired, rendering its representations false and misleading." Oleske Affirmation at ¶41. Indeed, according to the sworn testimony of the Oleske Affirmation, evidence produced by Exxon and its independent auditor, PwC, indicates that Exxon made "no attempt at all . . . to incorporate a proxy cost of GHGs into the economic models of cash flows used in determining whether a trigger for impairment testing existed or whether Exxon's assets were actually impaired prior to 2016." Oleske Affirmation at ¶49.

106. For the same reasons as set forth in Section IV.A.4 above concerning the Canadian Bitumen Operations, Exxon was also required to include the GHG "proxy costs" used

for its internal business planning purposes in connection with the Company's asset impairment calculations for its Rocky Mountain dry gas operations. According to the Oleske Affirmation, and Exhibit 5 attached thereto, by 2015, Exxon's internal policies would have required it to apply a $10 per ton proxy cost for emissions from its Rocky Mountain dry gas operations starting in 2018, which would then "ris[e] linearly" to $60 per ton in 2030.

107. Had Exxon incorporated the GHG "proxy costs" described in paragraph 106 above into the asset impairment calculations for its Rocky Mountain dry gas operations prior to 2016, the impact upon such calculations would have been significant. Indeed, using standard conversion rates of 117 pounds/MMBTU[20] and 2,200 pounds/ton (or, effectively, 0.05318 tons/MMBTU), a GHG "proxy cost" of $10/ton would result in the imposition of an additional cost of approximately $0.53/MMBTU, while a GHG "proxy cost" of $60/ton would result in the imposition of an additional cost of approximately $3.19/MMBTU. The unquestioned materiality of such costs is further illustrated by considering that, as of December 31, 2015, the Henry Hub spot price for natural gas was only $2.28/MMBTU. Clearly, the application of future costs ranging from approximately 23% to ***140%*** of the current price would have materially reduced expected future cash flows from these assets and had a material impact on any asset impairment calculation performed at year-end 2015.

V. LIMITING FACTORS AND ASSUMPTIONS

108. This declaration is provided solely for the purpose of court proceedings in the above-referenced matter and may not be used or referred to for any other purpose. The analysis and opinions contained in this declaration are based on information available as of the date of this declaration. I reserve the right to supplement or amend this declaration, including in the event additional information becomes available.

[20] *See* https://www.eia.gov/environment/emissions/co2_vol_mass.php.

I declare, under penalty of perjury, that the foregoing declaration is true and correct to the best of my knowledge. Dated this 20th day of July, 2017.

Charlotte J. Wright

CHARLOTTE J. WRIGHT, Ph.D., CPA

Exhibit 1

CHARLOTTE JEAN WRIGHT

July 2017

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EDUCATION

Doctor of Philosophy, August 1982; University of North Texas; Accounting, Finance, Economics, Research Methods

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Masters of Professional Accounting, August 1977; University of Texas at Arlington

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Certified Public Accountant –Oklahoma

BOARD POSITIONS

Member, International Accounting Standards Committee (IASC) - Extractive Industries Steering Committee, 1999-2002

International Accounting Standards Board Extractive Activities Advisory Committee, 2002-2009

PROFESSIONAL EXPERIENCE

2017 to Present: Oklahoma State University Regents Professor and Anadarko Petroleum Chair Emeritus, School of Accounting, Oklahoma State University

2008-present: CEO, Wright Resources International, PLLC.

2015 to 2017: Oklahoma State University Regents Professor and Anadarko Petroleum Chair, School of Accounting, Oklahoma State University

2014 to 2015: Anadarko Petroleum Chair and Professor of Accounting, School of Accounting, Oklahoma State University

2007 to 2014: Lanny G. Chasteen Chair and Professor of Accounting, School of Accounting, Oklahoma State University

1997 to 2007: Wilton T. Anderson Professor of Accounting, School of Accounting, Oklahoma State University

1996 to 2002: Director of Doctoral Program, School of Accounting, Oklahoma State University

1991 to 1997: Professor of Accounting, School of Accounting, Oklahoma State University

1986 to 1991: Associate Professor of Accounting, School of Accounting, Oklahoma State University. Tenured, July 1986

1982 to 1986: Assistant Professor of Accounting, School of Accounting, Oklahoma State University

1980 to 1982: Research Fellow, Extractive Industries Accounting Research Institute, University of North Texas

1979 to 1980: Instructor of Accounting, University of Texas at Arlington

1977 to 1979: Staff Accountant, Atlantic Richfield Company, Dallas, Texas

BOOKS AND BOOK CHAPTERS

Author, *International Petroleum Accounting*, 2nd edition; Tulsa, OK: Pennwell Publishing (revision in progress, release date uncertain)

Author, *Fundamentals of Oil and Gas Accounting*, 6th edition; Tulsa, OK: Pennwell Publishing (Fall 2016)

Author, Market Valuation of the Long-Run Effects of Effective Environmental Cost Strategies, in Randi Taylor Mancuso (Ed) *Environmental Cost Management*, (pp. 235 – 254). New York: Nova Science Publishers, Inc. with R. Burnett, and C. Sinkin (2010)

Author, *Fundamentals of Oil and Gas Accounting*, 5th edition; Tulsa, OK: Pennwell Publishing with R. Gallun (2008)

Author, *International Petroleum Accounting*, 1st edition; Tulsa, OK: Pennwell Publishing with R. Gallun (2004)

Author, *Fundamentals of Oil and Gas Accounting*, 4th edition; Tulsa, OK: Pennwell Publishing with R. Gallun, L. Nichols and J. Stevenson (2000)

Issues in Environmental Accounting, Chapter in *Accounting Theory,* 7th edition; Australia; John Wiley & Sons Australia (2010)

Accounting for International Operations. Chapter 25 in *Petroleum Accounting Principles, Procedures and Issues,* by Brock, Jennings and Feiten, 5th edition; Denton, TX: PDI

Accounting for Income Taxes. Chapter 24 in *Handbook of Natural Gas Accounting*, ed. D. L. Crumbley and V.Nichols. New York, NY: Executive Enterprises Publications Co., with T. Wetzel

RESEARCH PUBLICATIONS

Accounting for Climate Change: Valuation, Recognition and Implications, *Petroleum Accounting and Financial Management Journal* (forthcoming).

Revenue Recognition and Control in the Oil and Gas Industry: The End of the Entitlements Method? *Petroleum Accounting and Financial Management Journal* (2015) with R. Cornell and L. Fox.

Fair Market Value and Valuation Methods of Oil and Gas Properties, *Petroleum Accounting and Financial Management Journal* (2014) with R. Cornell.

Accounting for Leases: An update of Issues and Implications for the Oil and Gas Industry, *Petroleum Accounting and Financial Management Journal* (2013) with A. Spencer.

Accounting for Leases: Issues and Implication for the Oil and Gas Industry, *Petroleum Accounting and Financial Management Journal,* Vol. 30:3 (2011) with R. Cornell and W. Schwartz.

Variable Compensation and Employee Deception: A Management Note, *Petroleum Accounting and Financial Management Journal,* Vol. 30:3 (2011) with R. Cornell and W. Schwartz).

Eco-effective Cost Management: An Empirical Link Between Market Valuation and Environmental Sustainability, *Accounting and the Public Interest*, Vol. 11 (2011) with R. Burnett and C. Skousen.

Overview and Analysis of the IASB Extractive Activities Discussion Paper: Recommendations and Implications for Oil and Gas Accounting and Reporting, *Petroleum Accounting and Financial Management Journal,* Vol. 29:3 (2010) with C. Skousen.

How Successful is the FCPA at Combating Fraud: The Case of U.S. and Non-U.S. Oil and Gas Companies, *Petroleum Accounting and Financial Management Journal,* Vol.28:1 (2009) with C. Skousen.

Detecting and Predicting Financial Statement Fraud: The Effectiveness of the Fraud Triangle and SAS No. 99, *Advances in Financial Economics,* (2009) with C. Skousen and K. Smith. (2016- SSRN Top Ten List).

Market Valuation of the Long-Run Effects of Adoption of Effective Environmental Cost Strategies, *Environmental Cost Management*, (2009) with R. Burnett and C. Sinkin.

Assessing Fraud Risk: How Does the Oil and Gas Industry Stack Up? *Petroleum Accounting and Financial Management Journal*, Vol. 27: 2 (2008) with C. Skousen.

Contemporaneous Risk Factors and the Prediction of Financial Statement Fraud, *Journal of Forensic Accounting*, Vol. 9, No. 1 (June 2008) with C. Skousen.
Eco-Efficiency and Firm Value, *Journal of Accounting and Public Policy*, Vol. 27 (2008) with R. Burnett and C. Sinkin.

Corporate Governance and Investor Protection: Earnings Management in the UK and US. *International Journal of Accounting Research*. Vol 5:1 (2006) with J Shaw and L. Guan.

Employee Recognition and Assessment of Fraud Schemes: An International Perspective. *Petroleum Accounting and Financial Management Journal.* Vol 25:1 (2006), with and P. Dorr.

Earnings Management and Forced CEO Dismissal. *Advances in Accounting*. Vol. 21 (2005), with L. Guan and S. Leikam.

The Relative Information Content of the Components of Reserve Disclosures: Reserve Quantities versus the Standardized Measure. *International Journal of Accounting, Auditing and Performance Evaluation*. (December 2004) Vol. 1. No. 3 with K. Berry and W. Wilcox.

Earnings Management in Targeted Hostile Takeover Firms. *Journal of Forensic Accounting*. (July-December 2004) Vol. V, No. 2 with L. Guan and L. Sun.

Make It Easy and They Will Come. *Internal Auditor*. (Feb. 2004) Vol. LXI:1

Corporate Control and Accounting Policy Choices: The Case of MBOs. *Managerial Finance* (2004). Volume 30, No. 11 with L. Guan.

Accounting for Asset Retirement Obligations by Oil and Gas Producing Companies: The Past and the Future. *Petroleum Accounting and Financial Management Journal* (2003) Volume 22, No. 2.

Environmental Costs and Tax Policy: The Case of Future Dismantlement, Removal and Restoration Costs. *Oil, Gas and Energy Quarterly*. (Dec. 2003) Volume 52, No.2. with J Shaw.

Reliability and Relevance of Oil and Gas Reserve Disclosures: Does Accounting Research Provide the Answers? *International Journal of Accounting Literature* (2002) Volume 2, No. 1-4, with J Shaw and L. Owens.

Application of Design Benefit to Joint Cost Allocation: A Laboratory Simulation. *International Journal of Accounting Literature* (2001) Volume 1, No. 2-4, with K. Hall.

The Value Relevance of Oil and Gas Disclosures: An Assessment of the Market's Perception of Firms' Effort and Ability to Discover Reserves. *Journal of Business, Finance and Accounting* (2001) Volume 28, No. 5-6, with K. Berry.
Accounting for Site Closure and Environmental Costs: A New Maze of Standards and Requirements, *Oil, Gas and Energy Quarterly* (2000) Volume 48, No. 3.

Relevance versus Reliability of Oil and Gas Reserve Quantity and Value Disclosures: the Results of Two Decades of Research, *Petroleum Accounting and Financial Management Journal* (1999) Volume 18, No. 3, with H. Brock.

Allocation of Upstream Exploration, Drilling, Development and Production Costs to Petroleum Products: Issues and Alternatives, *Petroleum Accounting and Financial Management Journal* (1998) Volume 17, No. 3, with K. Hall.

Environmental Accounting: Implications for the Oil and Gas Industry, *Petroleum Accounting and Financial Management Journal*, (1998) Volume 17, No. 2.

Value-Relevant Reserve Quantity Disclosures: Oil Reserves versus Gas Reserves. *Petroleum Accounting and Financial Management Journal* (1997) Volume 16, No. 1, with K. Berry.

Site Exit Costs - New American Accounting Standards. *Oil & Gas Finance and Accounting* (1996) Volume 11, No. 4.

Accounting for Future Dismantlement and Environmental Reclamation Costs in the Oil and Gas Industry: A Survey of Current Problems and Practices. *Petroleum Accounting and Financial Management Journal* (1994) Volume 13, No. 3.

Financial Accounting Practices and 'Overcapitalization' of Mature Producing Properties: Some Observations. *Petroleum Accounting and Financial Management Journal* (Spring 1993) Volume 12, No. 1, with C. Brown and M. Landreth.

Unobservable Costs of Regulation: The Case of Firm Specific Tax Legislation. *Advances in Public Interest Accounting* (1992) Volume 5.

Accounting for Reclamation Costs. *COPAS National Quarterly* (May 1992).

Accounting Education via Satellite: Is Distance Learning a Viable Alternative? *Southwest Business Review* (1991) Volume 1, No. 1, with M. Mowen, A. Lau and L. Hammer.

Implementation of SFAS No. 96: The Latest Dilemma for Oil and Gas Producers. *Petroleum Accounting and Financial Management Journal* (1990) Volume 9, No. 2, with R. Edwards.

Accounting for Income Taxes: The Challenge Facing Oil and Gas Producers. *The Oil and Gas Tax Quarterly* (1989) Volume 38, No. 2, with T. Wetzel and L. Moyer.

The Market for Corporate Control and its Implications for Accounting Policy Choice. *Advances in Accounting* (1989) Volume 7, with J. Groff.

Detecting Confounding Events in Accounting Capital Markets Research: The Case of the Oil and Gas Industry. *Journal of Petroleum Accounting* (1987) Volume 6, No. 3.

Uses of Indexes and Data Bases for Information Release Analysis. *The Accounting Review* (1986) Volume 61, No. 1, with J. Groff.

Accounting for Future Environmental Reclamation Costs. *CPA 85* (1985) Volume 11, No. 2.

Disclosures for Oil and Gas Operations - Reliability and Relevance. *The Oil and Gas Tax Quarterly* (1985) Volume 33, No. 3, with K. Stocks.

Applying a Ceiling to Capitalized Costs under Successful Efforts Accounting - An Analysis of the EIARI Survey. *Journal of Extractive Industries Accounting* (1983) Volume 2, No. 1.

A Study of Effects of News Reports on Stock Prices: Implications for Reserve Quantity Disclosures. *Journal of Extractive Industries Accounting* (1982) Volume 1, No. 3.

Accounting for Reclamation Costs of Oil and Gas Operations. *Journal of Extractive Industries Accounting* (1982) Volume 1, No. 1.

An Evaluation of Standards for Programs and Schools of Professional Accounting. *AACSB Bulletin* (1979) Volume 15, No. 1, with M. Foran and A. Frakes.

SELECTED ACADEMIC PROCEEDINGS AND PRESENTATIONS

Market Valuation of Eco-Effective Cost Management and Environmental Sustainability, American Society of Business and Behavioral Sciences 19th Annual Conference, Las Vegas; February 2012 (Recipient Best Paper Award)

Eco-effective Cost Management: An Empirical Link between Market Valuation and Environmental Sustainability, Shidler Research Workshop, University of Hawaii, September 2010

Eco-effective Cost Management: An Empirical Link Between Market Valuation and Environmental Sustainability, American Society of Business and Behavioral Sciences Annual Conference, Las Vegas; February 2010

Market Valuation of the Long-Run Effects of Adoption of Effective Environmental Cost Strategies, American Accounting Association Annual Meeting, New York, NY: August 2009

Recognition of Fraud Schemes: The Effect of Education and Experience, American Society of Business and Behavioral Sciences Annual Conference, Las Vegas; February 2007 (Recipient Best Paper Award)

Detecting Financial Statement Fraud: An Empirical Assessment of the SAS No. 99 Fraud Risk Factors, BYU Accounting Research Symposium, Salt Lake City, UT: October 2005

Detecting Financial Statement Fraud: An Empirical Assessment of the SAS No. 99 Fraud Risk Factors, 2005 American Accounting Association Ethics Research Symposium, San Francisco

Corporate Governance and Investor Protection: An Investigation of MBOs in the US and UK, American Accounting Association Annual Meeting, San Francisco, CA: August 2005

Corporate Governance, Investor Protection and Earnings Management: An Investigation of UK MBOs, American Accounting Association International Section Mid-Year Conference, San Antonio, TX: February 2005

Business Strategy and Earnings Management. Southeast American Accounting Association annual conference, Lexington, KY; April 2004

Business Strategy and Earnings Management. American Society of Business and Behavioral Sciences Annual Conference, Las Vegas; February 2004 (Recipient of Best Paper Award)

Earnings Management in Targeted Hostile Takeover Firms. American Society of Business and Behavioral Sciences Annual Conference, Las Vegas; February 2004

Earnings Management and Forced CEO Dismissal. American Accounting Association Annual Meeting, Honolulu; August 2003

The Relative Information Content of the Components of Reserve Disclosures: Reserve Quantities versus the Standardized Measure. Emerging Issues in International Accounting and Business. Niagara Falls, Ontario; July 2003

Earnings Management and Forced CEO Dismissal. American Society of Business and Behavioral Sciences Annual Conference, Las Vegas; February 2003 (Recipient of Best Paper Award)

Strategic Fit, Accounting Information, and Firm Value: A Fundamental Analysis. Asian Pacific Conference on International Accounting Issues; November 2002

Strategic Fit, Accounting Information, and Firm Value: A Fundamental Analysis. European Accounting Association Annual Congress, Copenhagen, DK; April 2002 (Recipient of Outstanding Manuscript Award)

Corporate Control and Earnings Management: Evidence from MBOs. European Accounting Association Annual Congress, Copenhagen, DK; April 2002

Corporate Control and Accounting Policy Choices: The Case of MBOs. American Society of Business and Behavioral Sciences Annual Conference, Las Vegas; February 2002

Value Relevance of Oil and Gas Disclosures: An Assessment of the Market's Perception of Firms' Efforts and Abilities to Discover Reserves. Research Forum, American Accounting Association National Meeting, Dallas, TX; August 1997

Value Relevance of Oil and Gas Disclosures: an Assessment of the Market's Perception of Firms' Effort and Ability to Discover Reserves. (1997) Oklahoma State University School of Accounting Research Workshop, Stillwater, OK; March 1997

Education via Satellite: Has Technology Made Distance Learning an Effective Alternative? 11th International Conference on Technology and Education, University of London Institute of Education, London, England; March 1994

Accounting Policy Choice: Evidence of the Implications of the Market for Managerial Labor and the Market for Corporate Control. Second European Management Control Symposium, Paris, France; July 1992

Unobserved Costs of Regulation: The Case of Firm Specific Tax Legislation and Congressional Insider Trading. Research Forum, American Accounting Association National Meeting, Nashville, TN; August 1991

Unobserved Costs of Regulation: The Case of Firm Specific Tax Legislation and Congressional Insider Trading. The Critical Perspectives Symposium, New York, NY; March 199.

Accounting Education via Satellite: Is Distance Learning a Viable Alternative. American Accounting Association Southwest Region Meeting, Dallas, TX; February 1990

Accounting Policy Choice: Evidence of the Implications of The Market for Managerial Labor and The Market for Corporate Control. American Accounting Association National Meeting, Honolulu, Hawaii; August 1989

Accounting Policy Choice and the Market for Corporate Control. American Accounting Association Midwest Regional Meeting, Milwaukee, WI; April 1987

Uses of Indexes and Data Bases for Information Release Analysis: A Comment. American Accounting Association Southwest Regional Meeting, New Orleans, LA; March 1985

An Assessment of Disclosure Requirements for Oil and Gas Producers. American Accounting Association Southwest Regional Meeting, Houston, TX; March 1983

Accreditation Standards for Schools of Professional Accounting. American Accounting Association Western Regional Meeting, Reno, NV; April 1979

SELECTED PRESENTATIONS AT PROFESSIONAL MEETINGS AND CONFERENCES

Valuation of Oil and Gas Properties in a Dynamic Price Environment. Council of Petroleum Accountants Society, Anchorage, AK ; July 2016

11th Annual OSU Oil and Gas Accounting Conference, Tulsa, OK; November 2015

15th Annual Accounting and Financial Reporting Conference, Tulsa, OK; November 2015

COPAS Update. Council of Petroleum Accountants Society, Anchorage, AK ; May 2015

10th Annual OSU Oil and Gas Accounting Conference, Tulsa, OK; November 2014

14th Annual Accounting and Financial Reporting Conference, Tulsa, OK; November 2014

Accounting for Environmental Costs in Midstream Operations, OSU Midstream Energy Conference, Stillwater, OK; October 2014

Understanding Oil and Gas Companies' Financial Information. Council of Petroleum Accountants Society, Anchorage, AK ; May 2014

Accounting for Environmental Costs in Midstream Operations, OSU Midstream Energy Conference, Stillwater, OK; December 2013

9th Annual OSU Oil and Gas Accounting Conference, Tulsa, OK; November 2013

13th Annual Accounting and Financial Reporting Conference, Tulsa, OK; November 2013

Oil and Gas Accounting Update. Oklahoma Society of CPAs, Oklahoma City, OK; August 2013

Accounting for Environmental Costs in the Oil and Gas Industry. Council of Petroleum Accountants Society, Anchorage, AK ; May 2013

8th Annual OSU Oil and Gas Accounting Conference, Tulsa, OK; November 2012

12th Annual Accounting and Financial Reporting Conference, Tulsa, OK; November 2012

Oil and Gas Accounting Update. Oklahoma Society of CPAs, Oklahoma City, OK; August 2012

IFRS Update. Council of Petroleum Accountants Society, Anchorage, AK ; May 2012

Oil and Gas Reserve Reporting under the SEC's Revised Reserve Rules. Council of Petroleum Accountants Society, Anchorage, AK ; May 2010

Accounting for Asset Retirement Obligations in the Oil and Gas Industry. Thompson Knight Petroleum Industry Update, Houston, TX; February 2009

IASB Extractive Industries Accounting Update. CNOOC Petroleum Accounting Conference, Shekou, PRC ; June 2009

IASB Extractive Activities Update. Caribbean Basin Financial Accounting Conference, Port of Spain, Trinidad; August 2009

Economic Consequences of Global Petroleum Fiscal Policies. Caribbean Basin Financial Accounting Conference, Port of Spain, Trinidad; August 2008

IASB's Extractive Activities Project, Council of Petroleum Accountants Society, Houston, TX; March 2007

IASB Extractive Activities Update. Caribbean Basin Financial Accounting Conference, Port of Spain, Trinidad; August 2006

Accounting for Environmental Costs in the Oil and Gas Industry, PricewaterhouseCoopers Accounting Briefing, Port of Spain, Trinidad; July 2005

IASB Extractive Industries Accounting Update. Caribbean Basin Financial Accounting Conference, Port of Spain, Trinidad; October 2003

Accounting for Asset Retirement Obligations in the Oil and Gas Industry. Council of Petroleum Accountants Society, Tulsa, OK; December 2002

Accounting for Asset Retirement Obligations in the Oil and Gas Industry. PDVSA Petroleum Industry Social Responsibility Conference, Caracas, Venezuela; October 2002
Update on IASB's Extractive Industries Project, Council of Petroleum Accountants Society, Houston, TX; March 2002

Accounting for Asset Retirement Obligations in the Oil and Gas Industry, American Petroleum Institute National Meeting; Houston, TX; March 2002

International Aspects of Accounting for E&P Operations. Council of Petroleum Accountants Society, National Meeting; April 2001

Accounting for Extractive Industries: US GAAP versus IASC Standards. Caribbean Basin Conference on Environmental Issues in the Petroleum Industry, Paramaribo, Suriname; November 2000

Accounting for Future Site Dismantlement and Environmental Costs. Council of Petroleum Accountants Society, Oklahoma City, OK; February 2000

Environmental Accounting. Caribbean and Central American Petroleum Accounting Conference, Port of Spain Trinidad, June 1999

Environmental Accounting. North American Petroleum Accounting Conference, Dallas TX, November 1998

Emerging Issues in International Oil and Gas Operations. International Petroleum Accounting Conference, Denton, TX, April 1998

Environmental Accounting. South American Petroleum Accounting Conference, Caracas, Venezuela, November 1997

Emerging Issues in Accounting for Oil and Gas Producers. International Petroleum Accounting Conference, Denton, TX, November 1997

Environmental Accounting for Oil and Gas Producers. International Petroleum Accounting Conference, Denton, TX; September 1996

Environmental Accounting Update. Council of Petroleum Accountants Society, Tulsa, OK; February 1996

Impairment of Long-Lived Assets in Petroleum Operations. Council of Petroleum Accountants Society, Oklahoma City, OK; January 1996

Financial Accounting Requirements for Oil and Gas Producers-Some Long-Run Effects. International Petroleum Accounting Conference, Denton, TX; December 1992

Environmental Accounting for Oil and Gas Producers. Annual Conference, Council of Petroleum Accountants Society, Oklahoma City, OK; December 1991

Unobserved Costs of Regulation: The Case of: Rifle-Shot Transitional Rules. Research Workshop -University of Arkansas, Fayetteville, AR; October 1991

Accounting and Decision Making by U.S. Oil and Gas Companies. Beijing International Symposium of Finance and Accounting, Beijing, PRC; May 1991

The Market for Corporate Control and its Implications for Accounting Policy Choice. Research Workshop - University of Arkansas, Fayetteville, AR; March 1988

The Market for Corporate Control and its Implications for Accounting Policy Choice. Research Workshop - Oklahoma State University, Stillwater, OK: October 1988 (with J. Groff)

Information Release Analyses in Capital Markets Research. Research Workshop - University of Arkansas, Fayetteville, AR; October 1984

Information Release Analysis in Capital Markets Research. Research Workshop - Oklahoma State University, Stillwater, OK; April 1983 (with J. Groff)

The Implications of Reclamation Costs on the Accounts of Canadian Oil and Gas Companies. University of Calgary Research Symposium, Calgary, Alberta; February 1983

An Assessment of the Effects of News Announcements on Stock Prices of Oil and Gas Companies. University of Calgary Research Symposium, Calgary, Alberta; February 1983

WORKING PAPERS AND RESEARCH IN PROGRESS

"Accounting for Environmental Costs: Valuation and Recognition" target: *Petroleum Accounting and Financial Management Journal*.

"Firm Value and the Disclosure of Probable and Possible Oil and Gas Reserves." (with R. Cornell) (data gathering)

"Eco-efficiency, Eco-effectiveness and Sustainability in Accounting Research." (with R. Burnett) target: *Journal of Accounting Literature*

"Strategic Fit and Oil and Gas Reserve Value Information: Predicting Firm Value." (with R. Cornell) (early stage)

GRANTS AND FUNDED RESEARCH

Future Environmental Reclamation Costs: An Investigation of Measurement Alternatives and the Development of a Functional Model for Financial Disclosure. ($16,426) grant from the Oklahoma State University Center for Energy Research, May 1989

Public Policy and Resource Allocation Implications of Rifle-Shot Transitional Rules. Dean's Excellence Fund Grant ($11,000), January 1989

Intra-Industry Information Transfers and Firm Size. School of Accounting Research Grant ($10,000), June 1986

The Impact of Changes in Oil Industry Tax Preferences on the Oklahoma Economy. $68,000 grant from the Oklahoma State University Center for Energy Research, May 1986

Uses of Indexes and Data Bases for Information Release Analysis. Dean's Excellence Fund Grant ($8,000), June 1985

DISSERTATION SUPERVISION

K. Berry (chair)

C. Skousen (chair)

C. Sinkin (chair)

A. Belehe (chair)

P. Clayton

B. Askren

C. Patterson

L. Owens (chair)

J Shaw (chair)

R. Burnett

TEACHING

Advanced Accounting

Cost Accounting

Introductory Financial Accounting

Intermediate Financial Accounting

Introductory Managerial Accounting

Graduate Seminar in International Petroleum Accounting

Graduate Seminar in Accounting Theory

Accounting Doctoral Seminar

UNIVERSITY SERVICE

School of Accounting:

Chair, School of Accounting Personnel Committee, 2008-present, member 1991-present
Director, School of Accounting Oil and Gas Accounting Conference, 2005-present
Director, School of Accounting, Accounting and Financial Reporting Conference, 2012-present
School of Accounting Hall of Fame Committee, 2012-present
Chair, School of Accounting Professorship Committee, 2008-present
Chair, School of Accounting Financial Curriculum Committee, 2009-present
Chair, School of Accounting Clinical Faculty Committee, 2012-present
School of Accounting Master's Program Committee, 2011-present
School of Accounting Scholarship Committee, 2012-present
Director, Doctoral Program in Accounting, 1996 – 2002
School of Accounting Doctoral Program Advisory Committee, 1996-2002, 2007-2012
Undergraduate Curriculum Committee, 2002-2006
Author, School of Accounting AACSB accreditation self-evaluation report, 1997 – 1999
Author, School of Accounting program review for the Oklahoma State Regents for Higher Education, 1994-95
School of Accounting Doctoral Program Admissions Committee, 1989-1992
School of Accounting Scholarship Committee, 1982-83

Spears School of Business:

Spears School of Business CEPD Faculty Outreach Award Committee, 2016
Spears School of Business Dean's Search Committee, 2014
Spears School of Business Faculty Issues Committee, 2007-2010
School of Business Doctoral Programs Advisory Committee, 1996-2002
School of Business Dean's Search Committee, 1999-2000
School of Business Curriculum Committee, 1990-1993, chair 1992-93
School of Business Centennial Professorship Committee, 1987
Faculty sponsor - Beta Gamma Sigma, 1985-1990 and 2012-13
College of Business Extension Committee, 1983-1990, 1995-1996

Oklahoma State University:

Guest Speaker, OSU Graduate Commencement, Spring 2016
Regents Distinguished Research Award selection committee, 2012, 2015

Ad Hoc Faculty Council Committee to Examine Current OSU Policy on External Activities, 2008
Dean's Search Committees, 1999-2000, 2002-2003, 2013-2014
University Student Conduct Committee, 1995-2005
University Termination Hearing Board, 1994-2004

PROFESSIONAL SERVICE AND APPOINTMENTS:

Member, International Accounting Standards Committee (IASC) - Extractive Industries Steering Committee, 1999-2002

International Accounting Standards Board Extractive Activities Advisory Committee, 2002-2009

Director, Southwest American Accounting Association Doctoral Consortium, 1999

Planning Committee, Southwest American Accounting Association Doctoral Consortium, 1997-2000

Chair, Southwest Region American Accounting Association Advisory Committee, 1990-1991
Secretary-Treasurer, Southwest Region American Accounting Association, 1988-1990

EDITORIAL REVIEW BOARDS

Ad Hoc Reviewer, *Journal of Accounting and Public Policy,* 2008, 2015, 2016

Ad Hoc Reviewer, British Journal of Education, Society & Behavioural Science, 2013-14

Editorial Review Board, *Petroleum Accounting and Financial Management Journal,* 1983-present

Editorial Review Board, *International Journal of Accounting Literature,* 2000-present

Ad Hoc Reviewer, *Journal of Sustainable Ecology*, 2011-present

Editorial Review Board, *Oil, Gas and Energy Quarterly,* 2005-present

Ad Hoc Reviewer, *The Accounting Review*, 1990-2002

Ad Hoc Reviewer, *Issues in Accounting Education*, 1996-2014

Author, Environmental Issues Column, *Petroleum Accounting and Financial Management Journal,* 1993-2010

Guest Editor, *Petroleum Accounting and Financial Management Journal,* Spring 1995

PROFESSIONAL EDUCATION AND CONSULTING – SELECTED COMPANIES

Amerada Hess Corporation (Houston)

Amoco Production Company (Tulsa, Houston, Denver)

Amoco Bolivia (Santa Cruz)

Amoco China Ltd.(Shekou)

Amoco China JV (Beijing)

ARCO Indonesia (Jakarta)

Anadarko Petroleum

Anadarko Mozambique Area 1, Lda.(Maputo)

Angola LNG (Luanda, Angola

Asia-America Gas (Beijing)

Australian Energy Advisors Pty. Ltd., Melbourne, Australia

BHP Billiton (Port of Spain)

BP p.l.c. (London)

BP America (Houston)

BP Egypt (Cairo)

BP Azerbaijan (Baku)

BP Angola (Luanda)

BP Indonesia (Jakarta)

BP Vietnam (HoChiMin City)

BP Scotland (Aberdeen)

BP Middle East (Dubai)

BP China (Beijing)

BP Trinidad (Port of Spain)

British Gas (Port of Spain)

Cabinda Gulf Oil Company Limited (Angola)

Chinese National Offshore Oil Company (Beijing, Shekou, Zhenjing)

Chinese National Petroleum Company (Beijing)

Chevron Global Upstream (Bangkok)

Chevron (Houston)

ConocoPhillips USA (Houston, Bartlesville)

ConocoPhillips Canada (Calgary)

ConocoPhillips Scotland (Aberdeen)

ConocoPhillips Norway (Stavinger)

ConocoPhillips China (Beijing, Shekou)

COPAS Alaska

COPAS Canada

COPAS Houston

Devon Energy (Oklahoma City)

Gas and Fuel Corporation of Victoria (Melbourne)

Gascor Pty Ltd (Melbourne)

Hogan Taylor (Tulsa)

Husky Oil China Ltd (Beijing)

IFRS Consultants (Trinidad, Lagos)

Institute of Petroleum (London)

Internal Revenue Service (Dallas, Washington DC)

Kerr-McGee China Petroleum LTD

Kirkland and Ellis (Chicago)

PDVSA (Caracas, Maracaibo)

Petroleum Company of Trinidad and Tobago Limited (Pointe-a-Pierre)

PricewaterhouseCoopers Trinidad (Port of Spain)

Professional Development Institute (Denton, TX)

PTT Exploration and Production Public Company Limited (Thailand)

QHD 32-6 Operating Company (ChevronTexaco/CNOOC joint venture)(Tanggu)

Robbins Geller Rudman & Dowd LLP (San Diego)

Roc Oil (Bohai) Company (Beijing)

Ryder Scott Company, L.P. (Houston)

Shell Oil Company (Houston, New York)

Staatsolie Maatschappij Suriname N.V. (Paramaribo)

State of Alaska (Anchorage, Juneau)

Toronto-Dominion (Toronto)

Wilmer Cutler Pickering Hale and Dorr LLP (New York and London)

U. S. Department of Treasury (Washington DC)

LITIGATION SUPPORT

Unocal Pipeline Company v BP Pipelines (Alaska) Inc., et al (2014-2015).

Chevron China Energy Company v ENI China B.V. (2014-2015) (written report, oral testimony at arbitration).

Choice Exploration, et al v. Weatherford U.S. et al (2014-2015) (written reports).

Wilmer Cutler Pickering Hale and Dorr LLP consulting regarding Karachaganak Production Sharing Agreement (Kazakhstan) (2015).

BP America, Inc. Deepwater Horizon Litigation (2014-2016) (consulting).

John K. Meyer, et. al v JP Morgan Chase Bank N.A., Individually/Corporately and as Trustee of the South Texas Syndicate Trust and Gary P. Aymes (2014). (written report, deposition).

Wintershall Energia S.A. v Total Austral S.A. and Pan American Sur S.A. (2011-2013) (consulting).

Otoe-Missouria Tribal Trust Fund Reconciliation (2011-2012) (consulting).

Various cases involving Enron Corp. and Toronto-Dominion Bank (witness for Toronto-Dominion Bank) (2006-2014) (consulting)

Anadarko Petroleum Corporation v. Comptroller of Public Accounts for the State of Texas. (2007-2012) (witness for Anadarko Petroleum Corporation). (consulting; written report)

Cabinda Gulf Oil Company Limited v. the Ministry of Finance, Republic of Angola (2008). (consulting; written opinion)

Bolack Minerals Co. v. Burlington Resources Oil and Gas Co, CV. No. 97-96-1 (11th Judicial District Ct., San Juan County, New Mexico) (2006-2007). (written report; deposition)

Watts Ranch LLC, et al v. Amoco Production Company, Case No. C-2001-73 and Chockley, et al v. Amoco Production Company, Case No. C-2002-84 (2006-2007). (consulting)

International Court of Arbitration: Korea National Oil Corporation (Peruvian Branch),

Daewoo International Corporation (Peruvian Branch), and SK Corporation (Peruvian Branch) v. Pluspetrol Norte S.A. (2004). (written report; oral testimony at arbitration)

Anschutz Company and Subsidiaries Qwest Communications Corporation (Qwest), a subsidiary of Anschutz Company v. Commissioner of Internal Revenue (2004-2005). (written report; trial testimony)

Central Resources, Inc. v Merit Partners, L.P., Merit Energy Partners, L.P., Merit Energy Company, and Merit Energy Partners III, L.P. (2004-2005). (consulting)

Lobo Exploration Co. v Amoco Production Company (1999-2005). (written report; deposition)

Clajon Gas Company LP, et al. v Commissioner of Internal Revenue; Utilicorp United Inc v Commissioner of Internal Revenue (2000-2001). (written report; trial testimony)

Chieftain International (U.S.) Inc. v Statoil Exploration (U.S.) Inc. c/w Chieftain International (U.S.) Inc. v Tri-Union Development Corporation (1999-2000). (written report; deposition)

Exxon Corporation and Affiliated Companies v. Commissioner of Internal Revenue (1995-1997). (written report; trial testimony)

ESSO Australia Resources LTD. and BHP Petroleum (North West Shelf) PTY. LTD. v. Gas and Fuel Corporation of Victoria, Australia (1993-96). (written reports)

Union Oil Company of California v. Commissioner of Internal Revenue (1994). (written report)

Amoco Production Company Successor by Merger with Amoco Rangeland Company et al v. Commissioner (1994). (consulting)

ESSO Australia Resources LTD. And BHP Petroleum (Bass Strait) PTY. LTD. v. Generation Victoria (formerly State Electricity Commission of Victoria, Australia (1994). (written report)

Richardson Properties v. Amoco Corporation (1994). (written report)

Houston Pipeline Company v. United States (civil) (1993). (consulting)

AWARDS AND HONORS

SSRN Top Ten List for, “Detecting and Predicting Financial Statement Fraud: The Effectiveness of the Fraud Triangle and SAS No. 99,” with C. Skousen and K. Smith (2016)

Oklahoma State University Spears School of Business Richard Poole Faculty Excellence Award (2014)

School of Accounting/Phillips 66 Exceptional Service Award (2014)

Anadarko Petroleum Chair (2014-present)

Oklahoma State University Regent's Distinguished Research Award (2011)

Oklahoma Outstanding Accounting Educator – Oklahoma Society of CPAs (2009)

Best Paper Award. American Society of Business and Behavioral Sciences Annual Conference (2012)

Lanny G. Chasteen Chair in Accounting (2007-2014)

Wilton T. Anderson Professorship in Accounting (1997-2007)

Best Paper Award. American Society of Business and Behavioral Sciences Annual Conference (2007)

International Accounting Standards Board Extractive Activities Advisory Committee (2002-2009)

Best Paper Award. American Society of Business and Behavioral Sciences Annual Conference (2004)

Outstanding Manuscript Award. European Accounting Association Annual Congress (2002)

Spears School of Business Faculty of the Month (2003, 2005, 2008)

OSU University Extension Faculty Excellence Award (1994)

Stanford Summer Tax Conference (1989)

American Woman's Society of CPA's National Literary Award (1986)

Beta Gamma Sigma Distinguished Business Faculty Member (1985)

Atlantic Richfield Dissertation Grant (1981-82)

Extractive Industries Accounting Research Institute Fellowship (1980-81)

American Accounting Association Doctoral Consortium (1981)

Drew Young Scholarship Award - Dallas Personnel Association (1975)

University of Texas at Arlington Academic Scholarships (1973-1976)

PROFESSIONAL ASSOCIATIONS AND MEMBERSHIPS

American Accounting Association
Beta Gamma Sigma
Beta Alpha Psi
Council of Petroleum Accountants Societies (inactive)

Exhibit 2

EXHIBIT 2
WCS DAILY SPOT PRICE (USD/bbl) VERSUS CANADIAN BITUMEN OPERATIONS' AVERAGE MINIMUM WCS BREAKEVEN PRICE (USD/bbl)

Date	WCS Daily Spot Price (USD/bbl)	Avg. Mininum WCS Breakeven Price (USD/bbl)	Difference (USD/bbl)
11/12/2015	$ 27.10	$ 27.12	$ (0.02)
11/13/2015	$ 25.79	$ 27.12	$ (1.33)
11/16/2015	$ 26.79	$ 27.12	$ (0.33)
11/17/2015	$ 26.02	$ 27.12	$ (1.10)
11/18/2015	$ 26.15	$ 27.12	$ (0.97)
11/19/2015	$ 26.52	$ 27.12	$ (0.60)
11/20/2015	$ 26.70	$ 27.12	$ (0.42)
11/23/2015	$ 26.95	$ 27.12	$ (0.17)
11/24/2015	$ 28.07	$ 27.12	$ 0.95
11/25/2015	$ 28.24	$ 27.12	$ 1.12
11/27/2015	$ 26.91	$ 27.12	$ (0.21)
11/30/2015	$ 27.65	$ 27.12	$ 0.53
12/1/2015	$ 27.55	$ 27.12	$ 0.43
12/2/2015	$ 25.49	$ 27.12	$ (1.63)
12/3/2015	$ 26.73	$ 27.12	$ (0.39)
12/4/2015	$ 25.97	$ 27.12	$ (1.15)
12/7/2015	$ 24.20	$ 27.12	$ (2.92)
12/8/2015	$ 24.21	$ 27.12	$ (2.91)
12/9/2015	$ 23.46	$ 27.12	$ (3.66)
12/10/2015	$ 22.81	$ 27.12	$ (4.31)
12/11/2015	$ 21.82	$ 27.12	$ (5.30)
12/14/2015	$ 22.61	$ 27.12	$ (4.51)
12/15/2015	$ 23.50	$ 27.12	$ (3.62)
12/16/2015	$ 21.77	$ 27.12	$ (5.35)
12/17/2015	$ 22.67	$ 27.12	$ (4.45)
12/18/2015	$ 22.46	$ 27.12	$ (4.66)
12/21/2015	$ 22.21	$ 27.12	$ (4.91)
12/22/2015	$ 22.54	$ 27.12	$ (4.58)
12/23/2015	$ 24.00	$ 27.12	$ (3.12)
12/24/2015	$ 24.60	$ 27.12	$ (2.52)
12/28/2015	$ 23.81	$ 27.12	$ (3.31)
12/29/2015	$ 24.87	$ 27.12	$ (2.25)
12/30/2015	$ 23.35	$ 27.12	$ (3.77)
12/31/2015	$ 23.79	$ 27.12	$ (3.33)
1/4/2016	$ 23.06	$ 28.13	$ (5.07)
1/5/2016	$ 21.97	$ 28.13	$ (6.16)
1/6/2016	$ 19.97	$ 28.13	$ (8.16)
1/7/2016	$ 19.02	$ 28.13	$ (9.11)
1/8/2016	$ 18.66	$ 28.13	$ (9.47)
1/11/2016	$ 16.61	$ 28.13	$ (11.52)
1/12/2016	$ 15.54	$ 28.13	$ (12.59)
1/13/2016	$ 15.78	$ 28.13	$ (12.35)
1/14/2016	$ 16.65	$ 28.13	$ (11.48)

Date	WCS Daily Spot Price (USD/bbl)	Avg. Mininum WCS Breakeven Price (USD/bbl)	Difference (USD/bbl)
1/15/2016	$ 15.12	$ 28.13	$ (13.01)
1/19/2016	$ 14.86	$ 28.13	$ (13.27)
1/20/2016	$ 14.50	$ 28.13	$ (13.63)
1/21/2016	$ 15.68	$ 28.13	$ (12.45)
1/22/2016	$ 18.19	$ 28.13	$ (9.94)
1/25/2016	$ 16.24	$ 28.13	$ (11.89)
1/26/2016	$ 16.85	$ 28.13	$ (11.28)
1/27/2016	$ 17.95	$ 28.13	$ (10.18)
1/28/2016	$ 18.47	$ 28.13	$ (9.66)
1/29/2016	$ 18.37	$ 28.13	$ (9.76)
2/1/2016	$ 15.87	$ 28.13	$ (12.26)
2/2/2016	$ 14.38	$ 28.13	$ (13.75)
2/3/2016	$ 16.78	$ 28.13	$ (11.35)
2/4/2016	$ 17.32	$ 28.13	$ (10.81)
2/5/2016	$ 16.89	$ 28.13	$ (11.24)
2/8/2016	$ 16.09	$ 28.13	$ (12.04)
2/9/2016	$ 14.29	$ 28.13	$ (13.84)
2/10/2016	$ 13.80	$ 28.13	$ (14.33)
2/11/2016	$ 14.01	$ 28.13	$ (14.12)
2/12/2016	$ 16.99	$ 28.13	$ (11.14)
2/16/2016	$ 16.59	$ 28.13	$ (11.54)
2/17/2016	$ 19.73	$ 28.13	$ (8.40)
2/18/2016	$ 20.33	$ 28.13	$ (7.80)
2/19/2016	$ 19.20	$ 28.13	$ (8.93)
2/22/2016	$ 20.64	$ 28.13	$ (7.49)
2/23/2016	$ 19.47	$ 28.13	$ (8.66)
2/24/2016	$ 19.55	$ 28.13	$ (8.58)
2/25/2016	$ 20.47	$ 28.13	$ (7.66)
2/26/2016	$ 20.28	$ 28.13	$ (7.85)
2/29/2016	$ 21.15	$ 28.13	$ (6.98)
3/1/2016	$ 22.00	$ 28.13	$ (6.13)
3/2/2016	$ 21.66	$ 28.13	$ (6.47)
3/3/2016	$ 21.07	$ 28.13	$ (7.06)
3/4/2016	$ 22.67	$ 28.13	$ (5.46)
3/7/2016	$ 24.85	$ 28.13	$ (3.28)
3/8/2016	$ 23.45	$ 28.13	$ (4.68)
3/9/2016	$ 24.84	$ 28.13	$ (3.29)
3/10/2016	$ 24.39	$ 28.13	$ (3.74)
3/11/2016	$ 25.10	$ 28.13	$ (3.03)
3/14/2016	$ 23.78	$ 28.13	$ (4.35)
3/15/2016	$ 22.74	$ 28.13	$ (5.39)
3/16/2016	$ 25.21	$ 28.13	$ (2.92)
3/17/2016	$ 26.95	$ 28.13	$ (1.18)
3/18/2016	$ 28.14	$ 28.13	$ 0.01
3/21/2016	$ 28.52	$ 28.13	$ 0.39
3/22/2016	$ 28.40	$ 28.13	$ 0.27

Date	WCS Daily Spot Price (USD/bbl)	Avg. Mininum WCS Breakeven Price (USD/bbl)	Difference (USD/bbl)
3/23/2016	$ 26.74	$ 28.13	$ (1.39)
3/24/2016	$ 26.41	$ 28.13	$ (1.72)
3/28/2016	$ 26.34	$ 28.13	$ (1.79)
3/29/2016	$ 25.13	$ 28.13	$ (3.00)
3/30/2016	$ 25.17	$ 28.13	$ (2.96)
3/31/2016	$ 25.19	$ 28.13	$ (2.94)
4/1/2016	$ 23.54	$ 27.61	$ (4.07)
4/4/2016	$ 22.45	$ 27.61	$ (5.16)
4/5/2016	$ 22.09	$ 27.61	$ (5.52)
4/6/2016	$ 22.90	$ 27.61	$ (4.71)
4/7/2016	$ 22.31	$ 27.61	$ (5.30)
4/8/2016	$ 25.32	$ 27.61	$ (2.29)
4/11/2016	$ 26.21	$ 27.61	$ (1.40)
4/12/2016	$ 28.02	$ 27.61	$ 0.41
4/13/2016	$ 27.36	$ 27.61	$ (0.25)
4/14/2016	$ 26.95	$ 27.61	$ (0.66)
4/15/2016	$ 25.81	$ 27.61	$ (1.80)
4/18/2016	$ 25.03	$ 27.61	$ (2.58)